CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-K
February 16, 2011

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

(Mark One)

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

For the fiscal year ended December 31, 2010

OR

o **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
000-53742	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	34-4375005

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

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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 þ No o	FirstEnergy Corp.
Yes o No þ	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 o No þ	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 þ No o	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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o	FirstEnergy Corp.
Yes o No þ	

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 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.

Yes o No þ	FirstEnergy Corp.
Yes þ No o	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

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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 þ	FirstEnergy Corp.
Accelerated filer o	N/A
Non-accelerated filer (do not check if a smaller reporting company) þ	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 o	N/A

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

Yes o No þ	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., $10,712,157,232 as of June 30, 2010; 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, 2011**
FirstEnergy Corp., $0.10 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	741,880
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**
Proxy Statement for 2011 Annual Meeting of Stockholders to be held May 17, 2011	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.

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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.

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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-lo 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.
- The impact of the regulatory process on the pending matters in the various states in which we do business.
- Business and regulatory impacts from ATSI s realignment into PJM Interconnection, L.L.C., economic or weather conditions affecting future sales and margins.
- Changes in markets for energy services.
- Changing energy and commodity market prices and availability.
- Financial derivative reforms that could increase our liquidity needs and collateral costs, replacement power costs being higher than anticipated or inadequately hedged.
- The continued ability of FirstEnergy s regulated utilities to collect transition and other costs.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission and coal combustion residual regulations.
- The potential impacts of any laws, rules or regulations that ultimately replace CAIR.
- The uncertainty of the timing and amounts of the capital expenditures needed to resolve any NSR litigation or other potential similar regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units).
- 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.
- Adverse legal decisions and outcomes related to Met-Ed s and Penelec s transmission service charge appeal at the Commonwealth Court of Pennsylvania.
- Any impact resulting from the receipt by Signal Peak of the Department of Labor s notice of a potential pattern of violations at Bull Mountain Mine No.1.
- 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.
- Changes in customers demand for power, including but not limited to, changes resulting from the implementation of state and federal 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 the impact of, among other factors, the increased cost of coal and coal transportation on such margins and the ability 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 uncertainty 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, 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 FirstEnergy s 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.

Dividends declared from time to time on FirstEnergy s common stock during any annual period may in aggregate vary from the indicated amount due to circumstances considered by FirstEnergy s Board of Directors at the time of the actual declarations. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrants business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events or otherwise.

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GLOSSARY OF TERMS

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

ATSI	American Transmission Systems, Incorporated, owns and operates transmission facilities
Beaver Valley	Beaver Valley Power Station
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
Global Rail	A joint venture between FirstEnergy Ventures Corp. and WMB Loan Ventures II LLC, that owns coal transportation operations near Roundup, Montana
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
Perry	Perry Nuclear Power Plant
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 WMB Loan Ventures LLC, 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

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
Allegheny	Allegheny Energy, Inc. is the parent holding company of Allegheny Supply, Monongahela Power Company, The Potomac Edison Company and West Penn Power Company
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARO	Asset Retirement Obligation
AS	Allegheny Energy Supply Company, LLC owns and operates non-nuclear generating facilities and purchases and sells energy and energy-related commodities

BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule

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GLOSSARY OF TERMS, Cont d.

CATR	Clean Air Transport Rule
CBP	Competitive Bid Process
CO_2	Carbon dioxide
CRDM	Control Rod Drive Mechanism
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
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
IFRS	International Financial Reporting Standards
IRS	Internal Revenue Service
ISO	Independent System Operators
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-Emitting Diode
LOC	Letter of Credit
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MDPSC	Maryland Public Service Commission
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody s	Moody s Investors Service, Inc.
MRO	Market Rate Offer
MTEP	MISO Regional Transmission Expansion Plan
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

NOAC	Northwest Ohio Aggregation Coalition
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
NYPSC	New York Public Service Commission
NYSEG	New York State Electric and Gas Corporation
OCC	Ohio Consumers Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation

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GLOSSARY OF TERMS, Cont d.

PCRB	Pollution Control Revenue Bond
PICA	Pennsylvania Intergovernmental Cooperation Authority
PJM	PJM Interconnection L. L. C.
POLR	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
PSCWV	Public Service Commission of West Virginia
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
RTEP	Regional Transmission Expansion Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Service
SB221	Ohio 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
SMIP	Smart Meter Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRECs	Solar Renewable Energy Credits
TBC	Transition Bond Charge
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VERO	Voluntary Enhanced Retirement Option
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission

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Part IV

PART I

ITEM 1. BUSINESS

Proposed Merger with Allegheny

As previously disclosed, on February 10, 2010, FirstEnergy entered into an Agreement and Plan of Merger, subsequently amended on June 4, 2010 (Merger Agreement), with Element Merger Sub, Inc., a Maryland corporation, its wholly-owned subsidiary (Merger Sub) and Allegheny a Maryland corporation. 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, would automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy, and Allegheny stockholders would own approximately 27% of the combined company. FirstEnergy would also assume all outstanding Allegheny debt.

Pursuant to the Merger Agreement, completion of the merger is conditioned upon, among other things, shareholder approval of both companies, which was received on September 14, 2010; the SEC s clearance of a registration statement registering the FirstEnergy common stock to be issued in connection with the merger, which occurred on July 16, 2010. Approval of the merger was received from the VSCC on September 9, 2010. Approval from the FERC and from the PSCWV was received on December 16, 2010. Approval from the MDPSC was received on January 18, 2011. On January 7, 2011, we were notified by the DOJ that it had completed its review of the merger and closed its investigation. The proposed merger is also conditioned upon receipt of the approval of the PPUC. The Merger Agreement also contains certain termination rights for both FirstEnergy and Allegheny, and further provides for the payment of fees and expenses upon termination under specified circumstances.

FirstEnergy and Allegheny currently anticipate completing the merger in the first quarter of 2011. Although FirstEnergy and Allegheny believe that they will receive the required authorizations, approvals and consents to complete the merger, there can be no assurance as to the timing of these authorizations, approvals and consents or as to FirstEnergy s and Allegheny s ultimate ability to obtain such authorizations, consents or approvals (or any additional authorizations, approvals or consents which may otherwise become necessary) or that such authorizations, approvals or consents will be obtained on terms and subject to conditions satisfactory to Allegheny and FirstEnergy. Further information concerning the proposed merger is included in the Registration Statement filed by FirstEnergy with the SEC in connection with the merger.

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. 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 13,436 MW of diversified capacity (FES 13,236 MW and JCP&L 200 MW). Within FES portfolio, approximately 7,157 MW, or 54.1%, consist of coal-fired capacity; 3,991 MW, or 30.2%, consist of nuclear capacity; 1,151 MW, or 8.7%, consist of oil and natural gas peaking units; 451 MW, or 3.4%, consist of hydroelectric capacity, 376 MW, or 2.8%, are from wind facilities; and 110 MW, or 0.8%, consist of capacity from FGCO s current 4.85% 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 and Pennsylvania. All FES units are currently dedicated to MISO except Beaver Valley and Seneca Pumped Storage Plant, which are designated as a PJM resource. Additionally, see FERC Matters for RTO Realignment.

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 SEC, 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. On December 17, 2009, the FERC authorized ATSI to transfer operational control of its facilities to PJM. As described below in FERC Matters the transfer is scheduled to occur on June 1, 2011. ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and applicable regulatory requirements to ensure reliable service to customers. Additionally, see FERC Matters for RTO Realignment. ATSI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and applicable state regulatory authorities.

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, NYPSC and PPUC, as applicable.

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

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

Utility Regulation

State Regulation

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

As a competitive retail electric supplier serving retail customers in Ohio, Pennsylvania, 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 although as explained herein effective June 1, 2011 transmission service over ATSI s facilities will be provided pursuant to PJM s open access transmission tariff. 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 Realignment.

The FERC regulates the sale of power for resale in interstate commerce in part 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 their 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 the operating nuclear 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 and ATSI continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Utilities and ATSI continue the application of regulatory accounting to those operations.

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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 POLR 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, FES, FGCO, FENOC and ATSI. The NERC, as the ERO, is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases self-reporting an item to Reliability*First*. Moreover, it is clear that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the 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, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system within the PJM region and found it to be in full compliance with all audited reliability standards. In May 2010, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system in the Midwest ISO region and, subject to certain nonmaterial items, found it to be in compliance with the audited reliability standards. FirstEnergy s PJM facilities are next due for the periodic audit by Reliability*First* in 2011.

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Ohio Regulatory Matters

The Ohio Companies operate under an ESP, which expires on May 31, 2011, that provides for generation supplied through a CBP. The ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the May 2009 CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million). Applications for rehearing of the PUCO order in the distribution case were filed by the Ohio Companies and one other party. The Ohio Companies raised numerous issues in their application for rehearing related to rate recovery of certain expenses, recovery of line extension costs, the level of rate of return and the amount of general plant balances. On February 2, 2011, the PUCO issued an Entry on Rehearing denying the applications for rehearing filed both by the Ohio Companies and by the other party.

On March 23, 2010, the Ohio Companies filed an application for a new ESP. The new ESP will go into effect on June 1, 2011 and conclude on May 31, 2014. The PUCO approved the new ESP on August 25, 2010 with certain modifications. The material terms of the new ESP include: a CBP similar to the one used in May 2009 and the one proposed in the October 2009 MRO filing; a 6% generation discount to certain low-income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (initial auctions scheduled for October 20, 2010 and January 25, 2011); no increase in base distribution rates through May 31, 2014; a load cap of no less than 80%, which also applies to any tranches assigned post auction; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. Rider DCR substitutes for Rider DSI which terminates under the current ESP. The Ohio Companies also agreed not to pay certain costs related to the companies   integration into PJM, for the longer of the five year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million dependent on the outcome of certain PJM proceedings, established a $12 million fund to assist low income customers over the term of the ESP, and agreed to additional energy efficiency benefits. Many of the existing riders approved in the previous ESP remain in effect, some with modifications. The new ESP resolved proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and the integration into PJM. FirstEnergy recorded approximately $39.5 million of regulatory asset impairments and expenses related to the ESP. On September 24, 2010, an application for rehearing was filed by the OCC and two other parties. On February 9, 2011, the PUCO issued an Entry on Rehearing denying the applications for rehearing.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to 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 0.75% reduction each year thereafter through 2018.

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 Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The Ohio Companies   three year portfolio plan is still awaiting decision from the PUCO, which is delaying the launch of the programs described in the plan. As a result, the Ohio Companies filed on January 11, 2011, a request for amendment of OE s 2010 energy efficiency and peak demand reduction benchmarks to levels actually achieved in 2010. Because the Commission indicated that it would revise all of the Ohio Companies   2010, 2011, and 2012 benchmarks when addressing the Ohio Companies   three year portfolio plan, and an order has yet to be issued on that plan, CEI and TE also requested a waiver of their respective yet-to-be defined 2010 energy efficiency benchmarks if and only to the degree one is deemed necessary to bring these companies into compliance with their 2010 energy efficiency obligations. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a penalty.

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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 served in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs 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 were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On March 10, 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark, which application is still pending. In July 2010, the Ohio Companies initiated an additional RFP to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2010 and 2011. As a result of this RFP, contracts were executed in August 2010. On January 11, 2011, the Ohio Companies filed an application with the PUCO seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio due to the insufficient quantity of solar energy resources reasonably available in the market. The PUCO has not yet ruled on that application.

On February 12, 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. On March 3, 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect on March 17, 2010. On April 15, 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season, and charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect on May 21, 2010, and the proceeding remains open. The hearing in the matter is set to commence on February 16, 2011.

Pennsylvania Regulatory Matters

The PPUC adopted a Motion on January 28, 2010 and subsequently entered an Order on March 3, 2010 which denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. On March 18, 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. By Order entered March 25, 2010, the PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed the plan to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and the plan for the use of these funds to mitigate future generation rate increases commencing January 1, 2011. The PPUC approved this plan on June 7, 2010. On April 1, 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should prevail in the appeal and therefore expect to fully recover the approximately $252.7 million ($188.0 million for Met-Ed and $64.7 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011. The argument before the Commonwealth Court, *en banc*, was held on December 8, 2010.

On May 20, 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the period June 1, 2010 through December 31, 2010, including marginal transmission losses as approved by the PPUC, although the

recovery of marginal losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The TSC for Met-Ed s customers was increased to provide for full recovery by December 31, 2010.
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 through a prudent mix of long-term, short-term and spot market generation supply with a staggered procurement schedule that varies by customer class, using a descending clock auction. On August 12, 2009, the parties to the proceeding filed a settlement agreement of all but two issues, and the PPUC entered an Order approving the settlement and the generation procurement plan on November 6, 2009. Generation procurement began in January 2010.
On February 8, 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. On July 29, 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn s June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC on August 14, 2009. This plan proposed 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 of approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the SMIP as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; denying the recovery of interest through the automatic adjustment clause; providing for the recovery of reasonable and prudent costs net of resulting savings from installation and use of smart meters; and requiring that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the SMIP for the Pennsylvania Companies. The PPUC entered its Order on June 9, 2010, consistent with the Chairman s Motion. On June 24, 2010, Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC s Order regarding the future ability to include smart meter costs in base rates. On August 5, 2010, the PPUC granted in part the petition for reconsideration by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

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 31, 2010, the accumulated deferred cost balance was a credit of approximately $37 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. On February 10, 2011, the NJBPU approved a stipulation which allows the change in rates to become effective March 1, 2011.

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 estimated at $736 million (in 2003 dollars). 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 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. On April 16, 2010, the NJBPU issued an order indefinitely suspending the requirement of New Jersey utilities to submit Utility Master Plans until such time as the status of the EMP has been made clear. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their operations.

FERC Matters

Rates for 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 SECA) during a 16-month transition period. In 2005, the FERC set the SECA for hearing. The presiding ALJ 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 was subject to review and approval by the FERC. On May 21, 2010, FERC issued an order denying pending rehearing requests and an Order on Initial Decision which reversed the presiding ALJ s rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. The Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy s liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon, settlements were approved by FERC on November 23, 2010, and the relevant payments made. Rehearings remain pending in this proceeding.

PJM Transmission Rate

On April 19, 2007, 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, 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 based on the amount of load served in a transmission zone. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology (DFAX), which is generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities.

The FERC s Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision on August 6, 2009. The court affirmed FERC s ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500+ kV facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

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 and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM s filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain eastern utilities in PJM bearing the majority of their costs. Numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. FirstEnergy and a number of other utilities, industrial customers and state commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. FERC is expected to act by May 31, 2011.

RTO Realignment

On December 17, 2009, FERC issued an order approving, subject to certain future compliance filings, ATSI s withdrawal from MISO and integration into PJM. This move, which is expected to be effective on June 1, 2011, allows FirstEnergy to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy s transmission assets and operations are divided between PJM and MISO. The realignment will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. In the order, FERC approved FirstEnergy s proposal to use a FRR Plan to obtain capacity to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years.

FirstEnergy successfully conducted the FRR auctions on March 19, 2010. Moreover, the ATSI zone loads participated in the PJM base residual auction for the 2013 delivery year. Successful completion of these steps secured the capacity necessary for the ATSI footprint to meet PJM s capacity requirements. On August 25, 2010, the PUCO issued an order in the 2010 ESP Case approving a settlement that, among other things, called for the PUCO to withdraw its opposition to the RTO consolidation. In addition, the order approved a wholesale procurement process, and certain retail choice policies, that reflected ATSI s entry into PJM on June 1, 2011.

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. FirstEnergy expects ATSI to enter PJM on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. Additional FERC proceedings are either pending or expected in which the amount of exit fees, transmission cost allocations, and costs associated with long term firm transmission rights payable by the ATSI zone upon its withdrawal from the Midwest ISO will be determined. In addition, certain parties may protest other aspects of ATSI s integration into PJM, and certain of these matters remain outstanding and will be resolved in future FERC proceedings. The outcome of these proceedings cannot be predicted.

MISO Multi-Value Project Rule Proposal

On July 15, 2010, MISO and certain MISO transmission owners jointly filed with FERC their proposed cost allocation methodology for certain new transmission projects. The new transmission projects described as MVPs are a class of MTEP projects. The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be wheeled through the MISO as well as to energy transactions that source in the MISO but sink outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO s Board approved the first MVP project the Michigan Thumb Project. Under MISO s proposal, the costs of MVP projects approved by MISO s Board prior to the anticipated June 1, 2011 effective date of FirstEnergy s integration into PJM would continue to be allocated to FirstEnergy. MISO estimated that approximately $11 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

On September 10, 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO s proposal to allocate costs of MVP projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the beneficiary pays approach). FirstEnergy also argued that, in light of progress to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO s MVP proposal.

On December 16, 2010, FERC issued an order approving the MVP proposal without significant change. FERC s order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO s tariffs obligate ATSI to pay all charges that attach prior to ATSI s exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC s order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy filed for rehearing of FERC s order. In its rehearing request, the Company argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. FirstEnergy cannot predict the outcome of these proceedings at this time.

Sales to Affiliates

FES has received authorization from FERC to make wholesale power sales to the Utilities. FES actively participates in auctions conducted by or on behalf of the Utilities to obtain the power and related services necessary to meet the Utilities POLR obligations. Because of the merger with FirstEnergy, AS is considered an affiliate of the Utilities for purposes of FERC s affiliate restriction regulations. This requires AS to obtain prior FERC authorization to make sales to the Utilities when it successfully participates in the Utilities POLR auctions.

FES currently supplies the Ohio Companies with a portion of their capacity, energy, ancillary services and transmission under a Master SSO Supply Agreement for a two-year period ending May 31, 2011. FES won 51 tranches in a descending clock auction for POLR service administered by the Ohio Companies and their consultant, CRA International on May 13-14, 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 POLR load of the Ohio Companies until May 31, 2011.

On October 20, 2010, FES participated in a descending clock auction for POLR service administered by the Ohio Companies and their consultant, CRA International, for the following periods: June 1, 2011 through May 31, 2012; June 1, 2011, through May 31, 2013; and June 1, 2010 through May 31, 2014. The Ohio Companies offered 17, 17, and 16 tranches for these periods, respectively. FES won 10, 7, and 3 tranches, respectively, for these periods. On January 25, 2011, the Ohio Companies conducted a second auction offering the same product for identical time periods. FES won 3, 0, and 3 tranches, respectively, for these periods. FES entered into a Master SSO Supply Agreement to provide capacity, energy, ancillary services, and congestion costs to the Ohio Companies for the tranches won. Under the ESP in effect for these time periods, the Ohio Companies are responsible for payment of noncontrollable transmission costs billed by PJM for POLR service.

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On October 18, 2010, FES participated in a descending clock auction for POLR service administered by both Met-Ed and Penelec and their consultant, National Economic Research Associates (NERA) for the following tranche products and delivery periods: Residential 5-month, Residential 24-month, Commercial 5-month, Commercial 12-month and Industrial 12-month. All 5-month delivery periods are from January 1, 2011 through May 31, 2011, all 12-month delivery periods are from June 1, 2011 through May 31, 2012 while all 24-month delivery periods are from June 1, 2011 through May 31, 2013. Met-Ed offered 7 Residential 5-month tranches, 4 Residential 24-month tranches, 6 Commercial 5-month tranches, 6 Commercial 12-month tranches and 1 Industrial tranche while Penelec offered 5 Residential 5-month tranches, 3 Residential 24-month tranches, 5 Commercial 5-month tranches, 5 Commercial 12-month tranches and 1 Industrial tranche.

For Met-Ed offerings, FES won 4 Residential 5-month tranches, 2 Residential 24-month tranches, 1 Commercial 5-month tranche, 1 Commercial 12-month tranche and zero Industrial tranches. For Penelec offerings, FES won 1 Residential 5-month tranche, 1 Residential 24-month tranche, zero Commercial 5-month tranches, zero Commercial 12-month tranches and zero Industrial tranches. FES entered into separate Supplier Master Agreements (SMA) to provide capacity, energy, ancillary services, and congestion costs with Met-Ed and Penelec for each product won. Under the terms and conditions of the SMA, Met-Ed and Penelec are responsible for payment of noncontrollable transmission costs billed by PJM.

On January 18 to 20, 2011 FES participated in a descending clock auction for POLR service administered by Met-Ed, Penelec, and Penn Power and their consultant, NERA for the following tranche products and delivery periods: Residential 12-month, Residential 24-month, Commercial 12-month and Industrial 12-month. All 12-month delivery periods are from June 1, 2011 through May 31, 2012 while all 24-month delivery periods are from June 1, 2011 through May 31, 2013. Met-Ed offered 3 Residential 12-month tranches, 4 Residential 24-month tranches, 6 Commercial 12-month tranches and 11 Industrial tranches. Penelec offered 3 Residential 12-month tranches, 2 Residential 24-month tranches, 5 Commercial 12-month tranches and 11 Industrial tranches. Penn Power offered 2 Residential 12-month tranches, 1 Residential 24-month tranche, 3 Commercial 12-month tranches and 3 Industrial tranches.

For Met-Ed offerings, FES won 1 Commercial 12-month tranche and zero for the remaining products. For Penelec and Penn Power offerings, FES won no tranches. FES entered into a SMA to provide capacity, energy, ancillary services, and congestion costs with Met-Ed for the product won. Under the terms and conditions of the SMA, Met-Ed is responsible for payment of noncontrollable transmission costs billed by PJM.

Capital Requirements

Our capital spending for 2011 is expected to be approximately $1.4 billion (excluding nuclear fuel). For 2012 and 2013 we anticipate average annual baseline capital expenditures of approximately $1.2 billion that excludes currently unplanned investment opportunities or future mandated spending. Baseline capital initiatives promote reliability, improve operations, and support current environmental and energy efficiency directives. Our capital investments for additional nuclear fuel are expected to be $133 million, $300 million and $183 million in 2011, 2012 and 2013, respectively.

Anticipated capital expenditures for the Utilities, FES and FirstEnergy s other subsidiaries for 2011, excluding nuclear fuel, are shown in the following table. Such costs include expenditures for the betterment of existing facilities and for the completion of generating capacity, construction, transmission lines, distribution lines, substations and other assets.

	2010 Actual[(1)]	**Capital Expenditures Forecast 2011**
	(In millions)	
OE	$ 138	$ 127
Penn	26	20
CEI	113	117
TE	46	37
JCP&L	190	181

Met-Ed	106	89
Penelec	135	121
ATSI	67	60
FGCO	581	215
NGC	333	393
Other subsidiaries	78	60
Total	$ 1,813	$ 1,420

(1) Excludes nuclear fuel.

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During the 2011-2015 period, maturities of, and sinking fund requirements for, long-term debt of FirstEnergy and its subsidiaries are:

	Long-Term Debt Redemption Schedule		
	2011	2012-2015	Total
		(In millions)	
FirstEnergy	$ 250	$	$ 250
FES	163	692	855
OE		150	150
Penn	1	4	5
CEI	20	396	416
JCP&L	32	149	181
Met-Ed		400	400
Penelec		150	150
Other[1]	(21)	229	208
Total	$ 445	$ 2,170	$ 2,615

[1] Includes elimination of certain intercompany debt.

The following tables display consolidated operating lease commitments as of December 31, 2010.

Operating Leases	Lease Payments	Capital Trust	Net
		(In millions)	
2011	$ 329	$ 116	$ 213
2012	365	125	240
2013	367	130	237
2014	363	131	232
2015	365	91	274
Years thereafter	2,150	32	2,118
Total minimum lease payments	$ 3,939	$ 625	$ 3,314

Operating Leases	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
2011	$ 192	$ 146	$ 4	$ 64	$ 6	$ 4	$ 3
2012	230	147	3	64	5	4	3
2013	236	147	3	64	5	4	3
2014	234	146	3	64	5	4	2
2015	238	146	3	64	4	4	2
Years thereafter	1,895	166	6	79	48	40	23
Total minimum lease payments	$ 3,025	$ 898	$ 22	$ 399	$ 73	$ 60	$ 36

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2011, FirstEnergy expects to satisfy these requirements with internal cash from operations external funds may also be raised in the capital markets as market conditions warrant. FirstEnergy also expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

FirstEnergy had approximately $700 million of short-term indebtedness as of December 31, 2010, comprised of borrowings under the $2.75 billion revolving line of credit described below. Total short-term bank lines of committed credit to FirstEnergy, FES and the Utilities as of January 31, 2011 were approximately $3.2 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, 2011, FES had a $100 million term loan in addition to a $1 billion credit limit associated with FirstEnergy s $2.75 billion revolving credit facility. Also, an aggregate of $395 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, 2011, is described in the following table.

Company	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	Aug. 2012	$ 2,750	$ 2,245
FES	Term loan	Mar. 2011	100	
Ohio and Pennsylvania Companies	Receivables financing	Various[2]	395	237
		Subtotal	$ 3,245	$ 2,482
		Cash		668
		Total	$ 3,245	$ 3,150

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) Ohio $250 million matures March 30, 2011; Pennsylvania $145 million matures June 17, 2011 with optional extension terms.

FirstEnergy s primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2010, the holding company received $850 million of cash dividends on common stock from its subsidiaries and paid $670 million in cash dividends to common shareholders.

As of December 31, 2010, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.4 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 $124 million and $26 million, respectively, as of December 31, 2010. As a result of the indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $394 million and $343 million, respectively, under provisions of their senior note indentures as of December 31, 2010.

Based upon FGCO s FMB indenture, net earnings and available bondable property additions as of December 31, 2010, FGCO had the capability to issue $1.7 billion of additional FMBs under the terms of that indenture. Based upon NGC s FMB indenture, net earnings and available bondable property additions, NGC had the capability to issue $695 million of additional FMBs as of December 31, 2010.

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

On August 27, 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station operating license for an additional twenty years, until 2037. On December 27 and 28, 2010, a group of petitioners filed a request for hearing, contending that FENOC failed to adequately consider wind or solar generation, or some combination thereof, as an alternative to license extension at Davis Besse. They further argued FENOC had failed to adequately assess the cost of a severe accident at Davis Besse. FENOC and the NRC staff responded to this pleading on January 21, 2011, demonstrating that none of the petitioners arguments were admissible contentions under the National Environmental Policy Act or NRC regulations. An Atomic Safety and Licensing Board panel is expected to determine whether a hearing is necessary in this matter.

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, 2010, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. FirstEnergy provides an additional $15 million parental guarantee associated with the funding of decommissioning costs for these units. 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 could also affect the values of the nuclear decommissioning trusts. The NRC recently issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of FirstEnergy s nuclear facilities. As a result, FirstEnergy s decommissioning funding obligations are expected to increase. 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 $1.4 billion (OE-$120 million, NGC-$1.22 billion, TE-$64 million) for replacement power costs incurred during an outage after an initial 26-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 $9 million (OE-$1 million, NGC-$8 million, and TE-less than $1 million).

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FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $61 million (OE-$5 million, NGC-$52 million, TE-$2 million, Met Ed, Penelec, and JCP&L-less than $1 million each) 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 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.

Hydro Relicensing

Yards Creek

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 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.

In February 2011 FirstEnergy and PSEG filed a joint application with FERC to renew the license for an additional fifty years. The companies are pursuing relicensure through FERC s Integrated License Application Process (ILP). Under the ILP process FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunity for intervention and protests by affected third parties. FERC may hold hearings during the 2-year ILP licensure period. FirstEnergy expects FERC to issue the new license within the remaining portion of the 2-year ILP period. 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 yearly as necessary to permit FERC to issue the new license.

Seneca

The Seneca (Kinzua) Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania. FGCO owns and operates the project. The current FERC license was issued on December 1, 1965, and will expire on November 30, 2015. FGCO expects to file its new license application on or before November 30, 2013. On November 23, 2010, FGCO filed its notice of intent to relicense and pre-application document (PAD). On November 30, 2010, the Seneca Nation of Indians (Salamanca, NY) filed a competing notice of intent to file a new license application and PAD. On January 28, 2011, FERC issued a notice of the competing notices of intent and PADs; commencement of prefiling process and scoping; request for comments on the PADs; and identification of issues and associated study requests.

FERC s ILP provides a 5 year period for preparation, submission and adjudication of the licenses. The first part is a 3-year period during which each of FirstEnergy and the Seneca Nation are to collect the information and conduct the studies necessary to support license applications. The second part is the same as the licensing process described above for Yards Creek.

Section 15 of the Federal Power Act provides that when there are competing license applications, insignificant differences between competing applications are not determinative and shall not result in transfer of the license for the project. Based on the facts and the law, FirstEnergy believes it qualifies for this incumbent preference . The timetable for a FERC decision cannot be predicted at this time.

Environmental Matters

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy s earnings and competitive position to the extent that FirstEnergy 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.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) under the CAA by burning lower-sulfur fuel, combustion controls and post-combustion controls, generating more electricity from lower-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

The Sammis, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NOx and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement.

In July 2008, three 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. Two of these complaints also 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. FGCO believes the claims are without merit and intends to defend itself against the allegations made in those three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against GenOn Energy, Inc. (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999) and Met-Ed. Specifically, these suits allege that modifications at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR permitting in violation of the CAA s PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. In September 2009, 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. The parties dispute the scope of Met-Ed s indemnity obligation to and from Sithe Energy.

In January 2009, the EPA issued a NOV to GenOn alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, 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 permitting in violation of the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station containing in all material respects identical allegations as the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification that was required 60 days prior to filing a citizen suit under the CAA. In January, 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking damages based on alleged modifications at the Homer City Power Station between 1991 to 1994 without preconstruction NSR permitting in violation of the CAA s PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the State of New York intervened and have filed a separate complaint regarding the Homer City Station. Mission Energy Westside, Inc. is seeking indemnification from Penelec, the co-owner 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 Westside, Inc. is under dispute and Penelec is unable to predict the outcome of this matter.

In January 2011, a complaint was filed against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking damages based on the Homer City Station s air emissions. The complaint was also filed against the former co-owner, NYSEG and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. The complaint also seeks certification as a class action and to enjoin the Homer City Station from operating except in a safe, responsible, prudent and proper manner. Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint.

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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. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake generating plant. FGCO intends to comply with the CAA, including the EPA s information requests, but, at this time, is unable to predict the outcome of this matter.

National Ambient Air Quality Standards

The EPA s CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. 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 opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the NOx 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. In July 2010, the EPA proposed the CATR to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management continues to assess the impact of these environmental proposals and other factors on FGCO s facilities, particularly on the operation of its smaller, non-supercritical units. In August 2010, for example, management decided to idle certain units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NOx emission caps under the EPA s CAIR program) and 15 tons per year by 2018. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups, 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. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. On January 20, 2011, the U.S. District Court for the District of Columbia denied a motion by the EPA for an extension of the deadline to issue final rules, ordering the EPA to issue such rules by February 21, 2011. The EPA also entered into a consent decree requiring it to propose MACT regulations for mercury and other hazardous air pollutants from electric generating units by March 16, 2011, and to finalize the regulations by November 16, 2011. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. 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. 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. 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.

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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. 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 concentrations of several key GHGs increase the threat of climate change and may be regulated as air pollutants under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s PSD program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A 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; include 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 establish 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.

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. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. 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. On December 6, 2010, the U.S. Supreme Court granted a writ of certiorari to the Second Circuit in *Connecticut v. AEP*. Briefing and oral argument are expected to be completed in early 2011 and a decision issued in or around June 2011. While FirstEnergy is not a party to this litigation, 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.

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 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). The EPA has taken the position 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 U.S. Supreme Court reversed one significant aspect of the

Second Circuit 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. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant s water intake channel to divert fish away from the plant s water intake system. On November 19, 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. Depending on the results of such studies and the EPA s further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

In June 2008, the U.S. Attorney s Office in Cleveland, Ohio 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

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, 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 residuals, including whether they should be regulated as hazardous or non-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. On May 4, 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA s hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. FGCO s future cost of compliance with any coal combustion residuals 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 EPA or 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, 2010, 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 $104 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $32 million) have been accrued through December 31, 2010. Included in the total are accrued liabilities of approximately $64 million for environmental remediation of former MGPs 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 19.2 million tons of coal for the year 2011, approximately 116% of its 2011 coal requirements of 16.6 million tons. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, West Virginia, Montana and Wyoming. The contracts expire at various times through December 31, 2030. FES has contracted sufficient storage to manage the coal inventory should that be necessary. 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 WMB Loan Ventures LLC and WMB Loan Ventures II LLC, 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 2012 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2011 and partially fill requirements through 2024. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2020. 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. The Davis-Besse fabrication contract also has an extension provision for services for additional consecutive reload batches through the current operating license period. 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 Beaver Valley Unit 1 through 2014. Davis-Besse has adequate storage through 2017. FENOC is taking actions to extend the spent fuel storage capacity for Beaver Valley Units 1 and 2 and Perry. Plant modifications to increase the storage capacity of the existing spent fuel storage pool at Beaver Valley Unit 2 are currently under NRC review with approval expected by mid-year 2011. Dry fuel storage is also being pursued at Beaver Valley with completion projected by the end of 2014. Perry dry fuel storage facilities have been completed with the initial dry fuel storage loading pending resolution of a technical issue with the NRC. The Perry initial dry fuel storage loading campaign is targeted for 2012. Both Beaver Valley 2 and Perry maintain sufficient fuel storage capability to continue operations through the targeted completion dates of their respective storage expansion projects. 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.

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. On March 3, 2010, the Department of Energy filed a motion to withdraw its Yucca Mountain license application with prejudice. The Atomic Safety and Licensing Board denied the Department s withdrawal motion on June 29, 2010. That decision is on appeal to the Commission. However, the current Administration has stated the Yucca Mountain repository will not be completed and a Federal review of potential alternative strategies is being performed.

In parallel, several parties filed actions in the U.S. Circuit Court of Appeals for the D.C. Circuit challenging the Department s authority to withdraw the license application in light of its obligations under the Nuclear Waste Policy Act. The first case filed was *In re: Aiken County*, filed on February 19, 2010. Robert L. Ferguson, et al. filed a petition on February 25, 2010; State of South Carolina filed on March 26, 2010; and State of Washington filed on April 13, 2010. These cases have since been consolidated. Arguments in the case are scheduled for March 22, 2011. In light of this uncertainty, FirstEnergy intends to make additional arrangements for storage capacity as a contingency for the continuing delays of 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. Natural gas is currently consumed primarily by peaking units and demand is forecasted at less than 1 million mcf in 2011. FirstEnergy purchased a partially completed combined cycle combustion turbine plant in Fremont Ohio. Construction is scheduled to be completed in 2011.

System Demand

The 2010 net maximum hourly demand for each of the Utilities was:

OE 5,610 MW on July 23, 2010;

Penn 1,028 MW on July 23, 2010;

CEI 4,418 MW on July 23, 2010;

TE 2,122 MW on July 23, 2010;

JCP&L 6,420 MW on July 6, 2010;

Met-Ed 2,932 MW on July 6, 2010; and

Penelec 2,884 MW on July 6, 2010.

Supply Plan

Regulated Commodity Sourcing

The Utilities have a default service obligation to provide power 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 Companies 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 was secured through a FERC-approved agreement with FES through 2010, transitioning to a PPUC-approved competitive procurement process in 2011. If any supplier fails 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 POLR.

Unregulated Commodity Sourcing

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 13,236 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.

FES has retail and wholesale competitive load-serving obligations in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey serving both affiliated and non-affiliated companies. FES provides energy products and services to customers under various POLR, shopping, competitive-bid and non-affiliated contractual obligations. In 2010, FES generation was used to serve two primary obligations affiliated companies utilized approximately 43% of FES total generation and retail customers utilized approximately 43% of FES total generation. Geographically, approximately 60% of FES obligation is located in the MISO market area and 40% is located in the PJM market area.

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.

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 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, New Jersey, 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. In Ohio, SB221 provides two options for pricing generation in 2009 and beyond through a negotiated rate plan or a competitive bidding process (see Ohio Regulatory Matters above). In Pennsylvania, all electric distribution companies are required to secure generation for customers in competitive markets effective January 1, 2011.

Seasonality

The sale of electric power is generally a seasonal business and weather patterns can have a material impact on FirstEnergy s operating results. Demand for electricity in our service territories historically peaks during the summer and winter months, with market prices also generally peaking at that time. Accordingly, FirstEnergy s annual results of operations and liquidity position may depend disproportionately on its operating performance during the summer and winter. Mild weather conditions may result in lower power sales and consequently lower earnings.

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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 transmission and distribution system infrastructure to improve performance, and develop new technologies for advanced energy and grid applications.

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Executive Officers

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander (A)(B)	59	President and Chief Executive Officer	*-present
		Chief Executive Officer (F)	*-present
W. D. Byrd (B)	56	Vice President, Corporate Risk & Chief Risk Officer	2007-present
		Director Rates Strategy	*-2007
L. M. Cavalier (B)	59	Senior Vice President Human Resources	2005-present
		Vice President	*-2005
M. T. Clark			
(A)(B)(C)(D)(E)(F)	60	Executive Vice President and Chief Financial Officer	2009-present
		Executive Vice President Strategic Planning & Operations	2008-2009
		Senior Vice President Strategic Planning & Operations	*-2008
C. E. Jones (A)(B)	55	Senior Vice President & President FirstEnergy Utilities	2010-present
		President (C) (D)	2010-present
		Senior Vice President Energy Delivery & Customer Service	2009-2010
		President FirstEnergy Solutions	2007-2009
		Senior Vice President Energy Delivery & Customer Service	*-2007
J. H. Lash (F)	60	President and Chief Nuclear Officer	2010-present
		Senior Vice President and Chief Operating Officer	2007-2010
		Vice President, Beaver Valley	*-2007
C. D. Lasky (E)	48	Vice President Fossil Operations	2008-present
		Vice President Fossil Operations & Air Quality Compliance	2007-2008
		Vice President	*-2007
G. R. Leidich (A)(B)	60	Executive Vice President & President FirstEnergy Generation	2008-present
		Senior Vice President Operations (B)	2007-2008
		President and Chief Nuclear Officer (F)	*-2007
D. C. Luff (B)	63	Senior Vice President Governmental Affairs	2007-present
		Vice President	*-2007
J. F. Pearson	56	Vice President and Treasurer	2006-present
(A)(B)(C)(D)(E)(F)		Treasurer	*-2006
D. R. Schneider (E)	49	President	2009-present
		Senior Vice President Energy Delivery & Customer Service (B)	2007-2009
		Vice President (B)	2006-2007
		Vice President (E)	*-2006
L. L. Vespoli			
(A)(B)(C)(D)(E)(F)	51	Executive Vice President and General Counsel	2008-present
		Senior Vice President and General Counsel	*-2008

H. L. Wagner (A)(B)	58	Vice President, Controller and Chief Accounting Officer	*-present
		Vice President and Controller (C)(D)(E)(F)	*-present

(A) Denotes executive officer of FirstEnergy Corp.

(B) Denotes executive officer of FESC

(C) Denotes executive officer of OE, CEI and TE.

(D) Denotes executive officer of Met-Ed, Penelec and Penn.

(E) Denotes executive officer of FES

(F) Denotes executive officer of FENOC

* Indicates position held at least since January 1, 2006.

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Employees

As of December 31, 2010, FirstEnergy s subsidiaries had a total of 13,330 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	2,796	295
OE	1,227	750
CEI	916	615
TE	394	287
Penn	207	154
JCP&L	1,434	1,097
Met-Ed	706	509
Penelec	899	642
ATSI	39	
FES	274	
FGCO	1,751	1,140
FENOC	2,687	982
Total	13,330	6,471

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. 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 could result in lost revenues and increased expenses, including higher operating and maintenance costs, purchased power costs and capital requirements. 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 $1.36 billion for FES, $666 million for OE and an aggregate of $622 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 POLR and default service obligations in the states we do business. In addition, the 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 and credit worthiness of participants 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 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.

Financial Derivatives Reforms Could Increase Our Liquidity Needs and Collateral Costs

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the Commodity Futures Trading Commission (CFTC), (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt end users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end users. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to protect.

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.

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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 $12.6 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 $375 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 $118 million (but not more than $18 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 million per incident but not more than $70 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. 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 and energy efficiency requirements 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 and winter 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., 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. 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 Economic Uncertainty 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. 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. The only regulatory approval pending is from the PPUC. The PPUC could 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 would 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 would 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.

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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 the states in which we do business. 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.

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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. On December 30, 2010, FES, FGCO, NGC and the Utilities filed to renew this authority for operations within PJM. 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 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.

The MISO has proposed changes to its rates and tariffs that may result or cause significant charges to ATSI or the Ohio Companies or Penn upon their respective withdrawal from the MISO on May 31, 2011. 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.

On February 1, 2011, ATSI filed its proposal with FERC for moving its transmission rate into PJM s tariffs. Numerous parties are expected to intervene and file responsive comments. Our expectation is that ATSI will enter PJM as scheduled on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. Additional FERC proceedings are either pending or expected in which the amount of exit fees, transmission cost allocations, and costs associated with long term firm transmission rights payable by the ATSI zone upon its departure from the Midwest ISO will be determined. In addition, certain other parties continue to protest aspects of the move into PJM, and certain of these matters remain outstanding and will be resolved in future FERC proceedings. A ruling by FERC 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. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery timeframe in Ohio and Pennsylvania. In New Jersey, we recover the costs for energy efficiency programs through the SBC. Currently only Ohio has provisions for recovery of 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

We may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations. For example, applicable standards under the EPA s NSR initiatives remain in flux. Under the CAA, modification of our generation facilities in a manner that causes increased emissions could subject our existing facilities to the far more stringent NSR standards applicable to new facilities.

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The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work believed by the companies to be routine maintenance. We are currently involved in litigation and EPA investigations concerning alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position in these environmental matters but FGCO is unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition. For a more complete discussion see Environmental Matters.

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 CO_2 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. This finding triggered several regulatory actions under the CAA, resulting, among other things in the regulation of GHG emissions from large stationary sources. 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.

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. 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. 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.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required FirstEnergy to measure GHG emissions commencing in 2010 and begin to submit reports commencing in 2011. 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 concentrations of several key GHGs increase the threat of climate change and may be regulated as air pollutants under the CAA. In May 2010, the EPA finalized new thresholds for GHG emissions that define when permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s PSD program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A 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; include 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 establish 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.

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.

The EPA s CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. 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 opinion. In July 2010, the EPA proposed the CATR to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial.

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury 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. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups, 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. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers, including boilers which do not use fossil fuels. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. On January 20, 2011, the U.S. District Court for the District of Columbia denied a motion by the EPA for an extension of the deadline to issue final rules, ordering the EPA to issue such rules by February 21, 2011. The EPA also entered into a consent decree requiring it to propose MACT regulations for mercury and other hazardous air pollutants from electric generating units by March 16, 2011, and to finalize the regulations by November 16, 2011. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

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, various states have water quality standards applicable to FirstEnergy s operations.

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 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). The EPA has taken the position 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 U.S. Supreme Court reversed one significant aspect of the Second Circuit 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. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant s water intake channel to divert fish away from the plant s water intake system. On November 19, 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by April 1, 2013. Depending on the results of such studies and the EPA s further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures. Also, 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.

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, 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 residuals, including whether they should be regulated as hazardous or non-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. On May 4, 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA s hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. FGCO s future cost of compliance with any coal combustion residuals 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 EPA or the states.

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 continued operation of generating plants.

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 announced a work plan to aid in its evaluation of the impact that the use of IFRS by U.S. public companies would have on the U.S. securities market. Given the results of the work plan, 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.

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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. Past 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. On September 28, 2010, S&P then affirmed the ratings and stable outlook of FE and its subsidiaries. On December 15, 2010, Fitch revised its outlook on FE and FES from stable to negative and affirmed the rating for FirstEnergy and its subsidiaries.

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 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), FGCO s and NGC 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 controls the following generation sources as of January 31, 2011, shown in the table below. Except for the leasehold interests, OVEC participation and purchased wind power referenced in the footnotes to the table, substantially all of the generating units are owned by NGC (nuclear) and FGCO (non-nuclear).

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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	94
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	50(d)
Clifty Creek Madison, IN	1-6	60(d)
Total		7,267
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
West Lorain Lorain, OH	1-6	545
Yard s Creek Blairstown		
Twp., NJ	1-3	200(g)
Wind power		376(h)
Other		174
Total		2,178
Grand Total		13,436

(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 4.85% 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.

(h) Includes 167 MW from leased facilities and 209 MW under power purchase agreements.

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 14,932 pole miles.

The Utilities electric distribution systems include 194,685 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 85,247,000 kV-amperes.

The transmission facilities that are owned by ATSI are currently operated on an integrated basis as part of MISO through May 31, 2011. Effective June 1, 2011, the ATSI transmission assets will be migrated from MISO and integrated into PJM. The transmission facilities of JCP&L, Met-Ed and Penelec are physically interconnected and are operated on an integrated basis as part of PJM.

FirstEnergy s distribution and transmission systems as of December 31, 2010, consist of the following:

	Distribution Lines	Transmission Lines	Substation Transformer Capacity**
OE	62,156	461	8,300,000
Penn	13,389	52	1,351,000
CEI	33,210		8,754,000
TE	17,592	81	2,497,000
JCP&L	22,668	2,549	20,078,000
Met-Ed	18,641	1,405	8,595,000
Penelec	27,029	2,860	12,409,000
ATSI*		7,524	23,263,000
Total	194,685	14,932	85,247,000

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

** Top rating of in-service power transformers only. Excludes grounding banks, station power transformers, and generator and customer-owned transformers.

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ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. REMOVED AND RESERVED

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 in Item 6.

Information for FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec is not disclosed because they are wholly owned subsidiaries of FirstEnergy and there is no market for their common stock.

Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy s 2011 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 2010.

	Period			
	October	**November**	**December**	**Fourth Quarter**
Total Number of Shares Purchased[a]	68,246	133,762	539,703	741,711
Average Price Paid per Share	$ 38.50	$ 35.99	$ 35.48	$ 35.85
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs				
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs				

(a) Share amounts reflect purchases on the open market to satisfy FirstEnergy s obligations to deliver common stock under its 2007 Incentive Compensation Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan and Stock Investment Plan. In addition, such amounts reflect shares tendered by employees to pay the exercise price or withholding taxes upon exercise of stock options granted under the 2007 Incentive Compensation Plan and the Executive Deferred Compensation Plan.

ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Revenues	$ 13,339	$ 12,973	$ 13,627	$ 12,802	$ 11,501
Income From Continuing Operations	$ 784	$ 1,006	$ 1,342	$ 1,309	$ 1,258
Earnings Available to FirstEnergy Corp.	$ 784	$ 1,006	$ 1,342	$ 1,309	$ 1,254
Basic Earnings per Share of Common Stock:					
Income from continuing operations	$ 2.58	$ 3.31	$ 4.41	$ 4.27	$ 3.85
Earnings per basic share	$ 2.58	$ 3.31	$ 4.41	$ 4.27	$ 3.84
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	$ 2.57	$ 3.29	$ 4.38	$ 4.22	$ 3.82
Earnings per diluted share	$ 2.57	$ 3.29	$ 4.38	$ 4.22	$ 3.81
Dividends Declared per Share of Common Stock(1)	$ 2.20	$ 2.20	$ 2.20	$ 2.05	$ 1.85
Total Assets	$ 34,805	$ 34,304	$ 33,521	$ 32,311	$ 31,196
Capitalization as of December 31:					
Total Equity	$ 8,513	$ 8,557	$ 8,315	$ 9,007	$ 9,069
Long-Term Debt and Other Long-Term Obligations	12,579	12,008	9,100	8,869	8,535
Total Capitalization	$ 21,092	$ 20,565	$ 17,415	$ 17,876	$ 17,604
Weighted Average Number of Basic Shares Outstanding	304	304	304	306	324
Weighted Average Number of Diluted Shares Outstanding	305	306	307	310	327

(1) Dividends declared in 2010, 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.

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.

	2010		2009	
First Quarter High-Low	$ 47.09	$ 38.31	$ 53.63	$ 35.63
Second Quarter High-Low	$ 39.96	$ 33.57	$ 43.29	$ 35.26

Third Quarter High-Low	$	39.06	$	34.51	$	47.82	$	36.73
Fourth Quarter High-Low	$	40.12	$	35.00	$	47.77	$	41.57
Yearly High-Low	$	47.09	$	33.57	$	53.63	$	35.26

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2005 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 105,822 and 105,518 holders of 304,835,407 shares of FirstEnergy s common stock as of December 31, 2010 and January 31, 2011, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11 to the consolidated financial statements.

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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-lo 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.

The impact of the regulatory process on the pending matters in the various states in which we do business.

Business and regulatory impacts from ATSI s realignment into PJM Interconnection, L.L.C., economic or weather conditions affecting future sales and margins.

Changes in markets for energy services.

Changing energy and commodity market prices and availability.

Financial derivative reforms that could increase our liquidity needs and collateral costs, replacement power costs being higher than anticipated or inadequately hedged.

The continued ability of FirstEnergy s regulated utilities to collect transition and other costs.

Operation and maintenance costs being higher than anticipated.

Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission and coal combustion residual regulations.

The potential impacts of any laws, rules or regulations that ultimately replace CAIR.

The uncertainty of the timing and amounts of the capital expenditures needed to resolve any NSR litigation or other potential similar regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units).

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.

Adverse legal decisions and outcomes related to Met-Ed s and Penelec s transmission service charge appeal at the Commonwealth Court of Pennsylvania.

Any impact resulting from the receipt by Signal Peak of the Department of Labor s notice of a potential pattern of violations at Bull Mountain Mine No.1.

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.

Changes in customers demand for power, including but not limited to, changes resulting from the implementation of state and federal 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 the impact of, among other factors, the increased cost of coal and coal transportation on such margins and the ability 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 uncertainty 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, 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 FirstEnergy s 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.

Dividends declared from time to time on FirstEnergy s common stock during any annual period may in aggregate vary from the indicated amount due to circumstances considered by FirstEnergy s Board of Directors at the time of the actual declarations. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrants business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events or otherwise.

FIRSTENERGY CORP.
MANAGEMENT S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

Earnings available to FirstEnergy Corp. in 2010 were $784 million, or basic earnings of $2.58 per share of common stock ($2.57 diluted), compared with $1.01 billion, or basic earnings of $3.31 per share of common stock ($3.29 diluted), in 2009 and $1.34 billion, or basic earnings of $4.41 per share ($4.38 diluted), in 2008.

Change in Basic Earnings Per Share From Prior Year	2010	2009
Basic Earnings Per Share Prior Year	$ 3.31	$ 4.41
Non-core asset sales/impairments	(0.37)	0.47
Generating plant impairments	(0.77)	
Litigation settlement	0.04	(0.03)
Trust securities impairments	0.03	0.16
Regulatory charges	0.45	(0.55)
Derivative mark-to-market adjustment	0.35	(0.42)
Organizational restructuring	0.14	(0.14)
Debt redemption premium	0.32	(0.31)
Merger transaction costs 2010	(0.16)	
Income tax resolution	(0.57)	0.68
Revenues	1.06	(1.85)
Fuel and purchased power	(0.68)	(0.09)
Amortization of regulatory assets, net	0.22	(0.02)
Investment income	(0.20)	0.20
Interest expense		(0.14)
Transmission expense	(0.20)	0.73
Other expenses	(0.39)	0.21
Basic Earnings Per Share	$ 2.58	$ 3.31

2010 was a transformational year for FirstEnergy, and one in which we built a strong foundation for future success.

On February 11, 2010, FirstEnergy and Allegheny announced a proposed merger that would create the nation s largest electric utility system, with:

- more than 6 million customers across ten regulated electric distribution subsidiaries in Ohio, Pennsylvania, New Jersey, Maryland and West Virginia,
- generation subsidiaries owning or controlling approximately 24,000 MWs of generating capacity from a diversified mix of coal, nuclear, natural gas, oil and renewable power, and
- transmission subsidiaries owning over 20,000 miles of high-voltage lines connecting the Midwest and Mid-Atlantic.

Pursuant to the terms of the merger, Allegheny shareholders would receive 0.667 of a share of FirstEnergy common stock in exchange for each share of Allegheny they own.

2010 also marked FirstEnergy s final transition year to competitive markets with the expiration of the rate cap on Met-Ed and Penelec s retail generation rates on December 31, 2010. Beginning in 2011, Met-Ed and Penelec obtain their power supply from the competitive wholesale market and fully recover their generation costs through retail rates. All of FirstEnergy s other regulated utilities previously transitioned to competitive generation markets.

The effects of the uncertainty in the U.S. economy continue to present challenges. Although economic recovery began across our service territories, power sales and deliveries have still not returned to pre-recessionary levels. Distribution deliveries in 2010 were 108.0 million MWH, compared with 102.3 million MWH in 2009, driven primarily by an

8.4% increase in deliveries to the industrial sector, with the largest gains from customers in the automotive and steel industries. Industrial usage is lagging pre-recessionary levels by approximately 11%. Residential sales were up 6%, primarily due to warmer weather during the summer of 2010. Wholesale power prices continued to be weak; however, generation output improved in 2010 with output of 74.9 million MWH compared to the 2009 output of 65.6 million MWH.

In the second half of 2010, FES entered into financial transactions that offset the mark-to-market impact of 500 MW of legacy purchased power contracts which were entered into in 2008 for delivery in 2010 and 2011 and which were marked to market beginning in December 2009. These financial transactions eliminate the volatility in GAAP earnings associated with marking these contracts to market through the end of 2011.

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FES continued implementation of its retail strategy by focusing on direct, governmental aggregation and POLR sales opportunities. As of February 8, 2011, FES committed sales (as a percentage of total projected sales) for 2011 and 2012 were 96% and 65% respectively.

Operational Matters

PJM RTO Integration

In March 2010 two FRR Integration Auctions were conducted by PJM on behalf of the Ohio Companies to secure electric capacity for delivery years June 1, 2011, through May 31, 2012, and June 1, 2012, through May 31, 2013. In the 2011/2012 auction, 27 suppliers participated and 12,583 MW of unforced capacity (the MW bid into the auction after adjusting for historical forced outage rates) cleared at a price of $108.89/MW-day. The 2012/2013 auction had 28 market participants, with 13,038 MW of unforced capacity clearing at a price of $20.46/MW-day. FirstEnergy plans to integrate its operations into PJM by June 1, 2011.

Nuclear Generation

On February 28, 2010, the Davis-Besse Nuclear Plant (908 MW) shut down for its 16th scheduled refueling outage to exchange 76 of 177 fuel assemblies and to conduct numerous safety inspections. During the outage, it was determined through testing that modification work also needed to be performed on certain CRDM nozzles that penetrate the reactor vessel head. Modifications of 24 of the 69 nozzles on the reactor head were completed and Davis-Besse returned to service on June 29, 2010. The plant was originally scheduled to have a new reactor vessel head installed in 2014. This timeline was voluntarily accelerated, and FirstEnergy plans to install the new reactor head in the fall of 2011.

On August 30, 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license. In a letter dated October 18, 2010, the NRC determined that the Davis-Besse license renewal application was complete and acceptable for docketing and further review. Davis-Besse currently is licensed until 2017; if approved, the renewal would extend operations for an additional 20 years, until 2037.

On October 2, 2010, Beaver Valley Nuclear Power Station Unit 1 (911 MW) began its scheduled refueling and maintenance outage. During the outage FENOC exchanged 60 of the 157 fuel assemblies, conducted safety inspections and performed routine maintenance work. The plant returned to service on November 4, 2010.

Coal and Gas Fired Generation

On March 31, 2010, FGCO closed the sale of its 340 MW Sumpter Plant in Sumpter, Michigan, to Wolverine Power Supply Cooperative, Inc. FirstEnergy recorded a $6 million impairment of the Sumpter plant in December 2009 and a loss of $9 million with the sale in the first quarter of 2010. The plant consists of four 85 MW natural gas turbines and represented FirstEnergy s only generation assets in Michigan.

On August 12, 2010, FirstEnergy announced that operational changes would be made to some of the smaller coal-fired units in response to the slow economy, the lower demand for electricity and uncertainty related to proposed new federal environmental regulations. Beginning September 2010, Bay Shore units 2-4, Eastlake units 1-4, the Lake Shore Plant, and the Ashtabula Plant, which total 1,620 MW of capacity, began operating with minimum three-day notice and in response to consumer demand. FGCO recognized an impairment of $303 million ($190 million after tax) related to these assets in 2010.

On November 17, 2010, we announced plans to cancel repowering Units 4 and 5 (312 MW) at the R.E. Burger Plant to generate electricity principally with biomass. FGCO recognized an impairment of $72 million ($45 million after tax) and permanently shut down these units on December 31, 2010, due to the current market conditions.

During the third quarter of 2010, FGCO re-evaluated the schedule for completing the Fremont Plant (707 MW) due to market conditions and the extension of the tax incentives included in the Small Business legislation through 2011. As a result, FGCO extended the plant s expected completion to December 31, 2011, to reduce overtime labor cost and outside contractor spend for the remainder of the project. On February 3, 2011, FirstEnergy and American Municipal Power, Inc., entered into a non-binding Memorandum of Understanding (MOU) for the sale of our Fremont Energy Center. The MOU provides, among other things, for the parties to engage in exclusive negotiations towards a definitive agreement expected to be executed in March, 2011, with a targeted closing date in July, 2011.

On December 28, 2010, FirstEnergy closed the sale of 6.65% of FGCO s participation interest in the output of OVEC (approximately 150 MW) to Peninsula Generation Cooperative, a subsidiary of Wolverine Power Supply Cooperative, Inc., effective December 31, 2010. FirstEnergy s remaining interest in OVEC is 4.85%. The gain from this transaction increased 2010 net income by $53.8 million.

The Signal Peak coal mining operation in Montana, a joint venture owned 50% by FirstEnergy, began production in December 2009, providing FirstEnergy flexibility with respect to coal commodity supply for its fossil generation fleet. As part of this 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. Signal Peak provides us with optionality to either burn its western coal in our units, or sell the coal through the venture to other domestic or international buyers.

Finally, in 2010 we completed a $1.8 billion environmental retrofit of the W.H. Sammis Plant in Stratton, Ohio. This project was designed to reduce SO_2 emissions by 95% at the plant and NOx emissions by 90% at its two largest units. This project was among the largest AQC retrofits ever completed in the United States.

Ohio Wind Power Project

On February 8, 2011, FES announced its agreement to purchase 100 MW of output from Blue Creek Wind Farm (304 MW), which is being built in western Ohio by Iberdrola Renewables. Under terms of the agreement FES will purchase 100 MW of the total output of the project for 20 years beginning in October 2012.

Financial Matters

Cash flow from operations in 2010 was at a record level of $3.1 billion. During the year we also completed refinancing $725 million of variable rate debt to fixed rate debt.

In April and June of 2010, FGCO, a subsidiary of FES, purchased $235 million of variable rate PCRBs and $15 million of fixed rate PCRBs, respectively, originally issued on its behalf. In August of 2010, FES completed the remarketing of the $250 million of PCRBs; $235 million were successfully converted from a variable interest rate to a fixed interest rate and the remaining $15 million of PCRBs remain in a fixed rate mode. The $235 million series now bears a per-annum rate of 2.25% and is subject to mandatory purchase on June 3, 2013. The $15 million series now bears a per-annum rate of 1.5% and is subject to mandatory purchase on June 1, 2011.

Subsequently, in October of 2010, FES completed the refinancing and remarketing of six series of PCRBs totaling $313 million. These series were converted from a variable interest rate to a fixed interest rate of 3.375% per-annum and are subject to mandatory purchase on July 1, 2015. On December 3, 2010, FES and Penelec completed the refinancing and remarketing of five series of PCRBs totaling $178 million. These series were converted from variable rate to fixed interest rates ranging from 2.25% to 3.75% per-annum and are subject to mandatory purchase.

In May of 2010, FirstEnergy terminated fixed-for-floating interest rate swap agreements with a notional value of $3.2 billion, which resulted in cash proceeds of $43.1 million. As of June 30, 2010, the debt underlying the $3.2 billion outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 6%, which the swaps converted to a current weighted average variable rate of 4%. On July 16, 2010, FirstEnergy terminated these fixed-for-floating interest rate swap agreements resulting in cash proceeds of $83.6 million. The related gain from both of those transactions will generally be amortized to earnings over the life of the underlying debt. As of December 31, 2010, there were no fixed-to-floating swaps hedging the consolidated interest rate risk associated with FirstEnergy s consolidated debt.

On June 1, 2010, Penn redeemed $1 million of 5.40% PCRBs, due 2013, and on July 30, 2010, redeemed $6.5 million of its 7.65% FMBs due in 2023.

On October 22, 2010, Signal Peak Energy and Global Rail Group, as borrowers, entered into a new $350 million senior secured term loan facility. The two-year syndicated bank loan is guaranteed by FirstEnergy and the other owners of the borrowers. The proceeds from the loan were used to repay bank borrowings ($63 million) and debt owed to FirstEnergy ($258 million) with the balance to be used for other general corporate purposes.

In February 2010, S&P issued a report lowering FirstEnergy s and its subsidiaries credit ratings by one notch, while maintaining its stable outlook. Moody s and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries. These rating agency actions were taken in response to the announcement of the proposed merger with Allegheny. On September 28, 2010 S&P affirmed the ratings and stable outlook of FE and its subsidiaries. On December 15, 2010, Fitch revised its outlook on FirstEnergy and FES from stable to negative and affirmed the rating for FirstEnergy and its subsidiaries.

Regulatory Matters

Ohio ESP

The Ohio Companies will be operating under a new ESP effective June 1, 2011 through May 31, 2014, which was filed in March 2010 and approved by the PUCO in August 2010. That ESP provides customers with no overall increase to base distribution rates during the plan period and limits the costs they will pay related to certain PJM transmission projects. The ESP provides the Ohio Companies with recovery of capital invested in their distribution businesses through a Delivery Capital Recovery Rider effective January 1, 2012, through May 31, 2014. Generation rates for the annual delivery periods during the plan are determined through a CBP which will be conducted every

October and January for generation service through May 31, 2014. The first two CBPs were conducted in October 2010 and January 2011. Both auctions consisted of one, two and three-year products. The results of these auctions were accepted by the PUCO. The next auction is scheduled for October 2011.

Pennsylvania Default Service Plan

On October 20, 2010, the PPUC approved the results of various auctions held to procure the default service requirements for Met-Ed and Penelec customers who choose not to shop with an alternative supplier. The auction was the last of four auctions for the five-month period of January 1, 2011 to May 31, 2011, and the second of four auctions to procure commercial default service requirements for the 12-month period of June 1, 2011 to May 31, 2012 and residential requirements for the 24-month period of June 1, 2011 to May 31, 2013. The PPUC also approved the default service RFP for the Residential Fixed Block On-Peak and Off-Peak energy products. On January 18-20, 2011, Met-Ed, Penelec and Penn conducted auctions to procure a portion of the default service requirements for their customers who choose not to shop with an alternative supplier. The January 2011 auction was the third of four auctions for Met-Ed and Penelec and the first of two auctions for Penn to procure commercial default service requirements for the 12-month period of June 1, 2011 to May 31, 2012 and residential requirements for the 24-month period of June 1, 2011 to May 31, 2013. For Met-Ed, Penelec and Penn commercial customers the tranche-weighted average price ($/MWH) was $69.97, $59.32 and $57.88, respectively, and for residential customers the tranche-weighted average price was $70.69, $59.74 and $55.39, respectively. This was also the first of two auctions held to procure residential service requirements for the 12-month period of June 1, 2011 to May 31, 2012. For Met-Ed, Penelec and Penn residential customers the tranche-weighted average price ($/MWH) was $67.43, $58.01 and $60.29, respectively. In addition, the January 2011 auction procured supply for Met-Ed and Penelec industrial customers Hourly Priced Default Service. For Met-Ed and Penelec, the average 12-month price ($/MWH) was $9.90 and $9.91, respectively. The PPUC approved the results of the January 2011 auctions on January 24, 2011.

Penn Power s settlement for approval of its Default Service Plan for the period of June 1, 2011 through May 31, 2013 was approved by the PPUC on October 21, 2010. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn's June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

Energy Efficiency, Smart Grid and Smart Meter Programs

On June 3, 2010, FirstEnergy and the DOE signed grants totaling $57.4 million that were awarded as part of the American Recovery and Reinvestment Act to introduce smart grid technologies in targeted areas in Pennsylvania, Ohio, and New Jersey. The DOE grants represent 50% of the funding for approximately $115 million FirstEnergy plans to invest in smart grid technologies. The PPUC, PUCO and NJBPU have approved recovery of the remaining costs not funded through the DOE grant for the smart grid programs in Pennsylvania, Ohio and New Jersey, respectively, and the programs are underway in all three states.

Pennsylvania s Act 129 (Act 129) requires all Pennsylvania electric distribution companies with more than 100,000 customers to install smart meter technology within 15 years. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision issued on January 28, 2010 and decided various issues regarding the SMIP for the Pennsylvania Companies. An order consistent with Chairman Cawley s Motion was entered on June 9, 2010. The companies filed a petition for reconsideration on a single portion of the order, and on August 5, 2010, the PPUC entered an order granting in part the petition for reconsideration. The Pennsylvania Companies SMIP will assess the technologies, vendors, capital cost, and potential benefits of smart meter technology during an assessment period that covers the next 24 months. The Pennsylvania Companies expect to incur approximately $29.5 million of costs during the assessment period which they expect to recover through the Smart Meter Technologies Charge rider. At the end of the assessment period, the Pennsylvania Companies will submit to the PPUC a deployment plan for the full scale deployment of smart meters. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

Act 129 also requires utilities to reduce energy consumption and peak demand, with electricity consumption reduction targets of 1% by May 31, 2011, and 3% by May 31, 2013, and a peak demand reduction target of 4.5% by May 31, 2013. The Pennsylvania Companies responded by offering a wide variety of programs to residential, commercial, industrial, governmental and non-profit customers through their PPUC-approved EE&C Plans.

JCP&L Rate Adjustment

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2010, the accumulated deferred cost balance was a credit of approximately $37 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. On February 10, 2011, the NJBPU approved a stipulation which allows the change in rates to become effective March 1, 2011.

On January 18, 2011, JCP&L provided information to the NJBPU regarding the proposed merger between FirstEnergy and Allegheny. A stipulation between JCP&L, Board Staff and Rate Counsel was also provided. The Board reviewed the Stipulation at its January 25, 2011 meeting and issued an Order on February 10, 2011 indicating that it did not object to the transaction proceeding.

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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).

Energy Delivery Services transmits and distributes electricity through our seven utility distribution companies and ATSI, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. This segment also purchases power for its POLR and default service requirements in all three states. Its revenues are primarily derived from the delivery of electricity within our service areas 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	1,037,000
Penn	Western Pennsylvania	160,000
CEI	Northeastern Ohio	751,000
TE	Northwestern Ohio	310,000
JCP&L	Northern, Western and East Central New Jersey	1,098,000
Met-Ed	Eastern Pennsylvania	553,000
Penelec	Western Pennsylvania	591,000
ATSI	Service areas of OE, Penn, CEI and TE	

Competitive Energy Services segment supplies electric power to end-use customers through retail and wholesale arrangements primarily in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. This business segment controls 13,236 MWs of capacity 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.

STRATEGY AND OUTLOOK

FirstEnergy s vision is to be 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.

Our near-term focus is on getting the merger closed and then successfully managing the merger integration process and capturing long-term value to benefit our customers, shareholders and employees.

The merger integration process is underway and is expected to create significant efficiencies and economies of scale as we share best practices across the new organization. Merger integration teams comprised of employees from both FirstEnergy and Allegheny began working in April 2010 to identify value drivers and estimate transaction benefits.

The proposed merger is a natural geographic fit that would bring together complementary assets and corporate cultures and create a strong company that is well-positioned for growth. Our strength is the diversity of our assets, and our strategic focus is on creating long-term value through our core operations distribution operations, transmission operations and competitive generation and retail operations.

In our distribution operations, we remain focused on reliability, customer service and safety, and maintaining stable earnings growth. Our combined company will be committed to meeting regulatory expectations and leveraging best practices across seven states and ten operating utilities. FirstEnergy s management structure and philosophy supports local authority and decision-making by maintaining a local presence, which includes regional offices for our utility operations.

Presently, our competitive generation portfolio of 13,236 MW contains a diverse mix of quality assets, including nuclear, coal, natural gas, wind and pumped storage.

In response to reduced customer demand and uncertainty related to proposed new federal environmental regulations, FirstEnergy announced in August 2010 operational changes at several fossil plants. Affected are nine units at four plants located on the shore of Lake Erie in Ohio, with 1,620 MW of total capacity. In September 2010, the units began operating with a minimum three-day notice and in response to customer demand. These operational changes provide future flexibility regarding potential plant retirements given the current ongoing uncertainty regarding future EPA mandates or environmental legislation. (see Environmental Outlook below). We plan to make a similar evaluation of Allegheny s fossil assets once the merger is completed; however, because most of Allegheny s supercritical units have already been retrofitted with environmental control equipment, it is the bulk of their older, regulated subcritical units that are most exposed to potential regulations.

In the fall of 2011, we plan to replace Davis-Besse s reactor vessel head, accelerating the original replacement scheduled in 2014. We expect this proactive approach to provide additional margins of safety and reliability.

Construction continues on our 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 of this facility by the end of 2011. On February 3, 2011, FirstEnergy and American Municipal Power, Inc. (AMP), entered into a non-binding Memorandum of Understanding (MOU) for the sale of our Fremont Energy Center. The MOU provides, among other things, for the parties to engage in exclusive negotiations towards a definitive agreement expected to be executed in March, 2011, with a targeted closing date in July, 2011. In addition to Fremont, Signal Peak has been identified as a non-strategic asset that could be made available for sale.

FirstEnergy has identified potential post-merger benefits in the competitive generation and retail business mostly related to expanding the FirstEnergy operating philosophy and model to the combined operation. These include:

- Economies of scale and best practices related to fuel procurement and transportation;
- Expanded use of fuel blending techniques;
- Generation asset reliability improvement;
- Dispatch optimization;
- Outage best practices; and
- Expansion of the retail sales growth strategy.

Our strategy is to sell our own physical generation output to sales channels in close proximity to our fleet at the highest achievable margins. Our retail business remains a key component of our strategy. FES continues to expand its regional reach through retail sales by using its competitive generation assets to back POLR, governmental aggregation and direct sales commitments.

Wholesale power prices remain under pressure in response to continued low gas prices, but we expect future improvements in power prices to benefit the combined fleet.

Financial Outlook

We remain committed to managing our operating and capital costs in order to achieve our financial goals and commitment to shareholders.

Our liquidity position remains strong, with access to more than $3.2 billion of liquidity, of which approximately $3.1 billion was available as of January 31, 2011.

Capital expenditures in 2011 are projected to be $1.4 billion, compared to $1.8 billion in 2010. We intend to continue to fund our capital requirements through cash generated from operations**.**

Positive earnings drivers for 2011 are expected to include:

- Increased retail revenues associated with FES POLR, governmental aggregation and direct sales;
- Reduced fuel expenses; and
- Increased margin from Signal Peak.

Negative earnings drivers for 2011 are expected to include:

- Decreased revenues associated with the expiration of the Met Ed/Penelec partial requirements agreement with FES;
- Increase in net ancillary, congestion, and capacity expenses;
- Increased purchased power expenses;
- Additional planned nuclear outage for Davis-Besse s reactor head replacement; and
- Increased depreciation expenses and reduced capitalized interest, primarily associated with the Sammis plant environmental project.

Distribution deliveries and non-fuel, non-outage O&M expenses including employee benefits are expected to be essentially flat in 2011 compared to 2010.

FirstEnergy s $2.75 billion revolving credit facility matures in August 2012. We intend to review our revolving credit facility needs post-merger and at a minimum anticipate pursuing renewal of the existing facility during the first half of 2011.

In December 2010, a new federal income tax law became effective that provides for bonus depreciation tax benefits. This new law is expected to provide approximately $500 million in additional cash to FirstEnergy through 2012.

We remain focused on liquidity and a strong balance sheet, as well as maintaining investment grade credit ratings. Our financial plan accelerates our goal of improving our financial strength and flexibility by significantly reducing debt by the end of 2012. In addition to cash generated from operations, we expect to deploy cash received through bonus depreciation tax benefits, as well as cash from the future sale of certain non-core assets, to this debt reduction initiative. These actions are expected to improve our credit metrics over the next several years.

Capital Expenditures Outlook

Our capital expenditure forecast for 2011 is projected to be $1.4 billion, which represents a $393 million decrease from 2010.

The main drivers of this decrease are the 2010 completion of the $1.8 billion Sammis AQC environmental compliance project and reduced spending for the Fremont facility, scheduled for completion in 2011.

Capital expenditures for our competitive energy services business (excluding the AQC project and Fremont facility) are expected to increase slightly in 2011. The primary cause is the previously announced decision to accelerate the replacement of the Davis-Besse nuclear reactor vessel head. This initiative began in 2010 and is expected to be completed in 2011. Other planned generation investments provide for maintenance of critical generation assets, deliver operational improvements to enhance reliability, and support our generation to market strategy.

For our regulated operations, capital expenditures are forecasted at $730 million in 2011. Approximately $100 million has been allocated to the transmission expansion initiative, which includes projects to satisfy transmission capacity and reliability requirements, transitioning to the PJM market, and connecting new load delivery and new wholesale generation points. Expenditures for Ohio and Pennsylvania energy efficiency and advanced metering initiatives are expected to be primarily reimbursed from distribution customers and federal stimulus funding. Other investments for transmission and distribution infrastructure are designed to achieve cost-effective improvements in the reliability of our service.

For 2012 and 2013 we anticipate average annual baseline capital expenditures of approximately $1.2 billion, exclusive of any additional opportunities or future mandated spending. Planned capital initiatives promote reliability, improve operations, and support current environmental and energy efficiency directives.

Actual capital spending for 2010 and projected capital spending for 2011 are as follows:

Capital Spending by Business Unit	**2010**	**2011**
	(In millions)	
Energy Delivery	$ 729	$ 630
Nuclear	324	320
Fossil	174	160
FES Other	21	10
Corporate	59	50
AQC	249	4
Baseline Capital Expenditures	$ 1,556	$ 1,174
Fremont Facility	148	56
Burger Biomass	7	
Transmission Expansion	79	100
Davis-Besse Reactor Vessel Head Replacement	23	90
	$ 1,813	$ 1,420

Environmental Outlook

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

We have spent more than $7 billion on environmental protection efforts since the initial passage of the Clean Air and Water Acts in the 1970s, and these investments are making a difference. Over the past five years, we have invested approximately $1.8 billion at our W.H. Sammis Plant in Stratton, Ohio, to further reduce emissions of SO_2 by over 95% and NOx by at least 64%. This is one of the largest environmental retrofit projects in the nation and was recognized by Platts as the 2010 construction project of the year. Since 1990, we have reduced emissions of NOx by more than 83%, SO_2 by more than 82%, and mercury by about 60%. Also, our CO_2 emission rate, in pounds of CO_2 per kWh, has dropped by 19% during this period. Emission rates for our power plants are lower than the regional average.

By the end of 2011, 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 SO_2 equipment controls thus significantly decreasing our exposure to 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 levels are exploring and implementing a wide range of responses. We believe our generation fleet is very well positioned to compete in a carbon-constrained economy. In addition, we believe that upon consummation of the proposed merger with Allegheny, our competitive position will be enhanced with an even more diverse mix of fully-scrubbed fossil generation, 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 CO_2 emissions. For example, since 1990, we have reconfigured our fleet by retiring nearly 1,000 MWs of older, coal-based generation and adding more than 1,800 MWs 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 CO_2 emissions. Today, nearly 40% of our electricity is generated without emitting CO_2 a key advantage that will help us meet the challenge of future governmental climate change mandates. And with recent announcements in 2009, including the expanded use of renewable energy, energy storage and natural gas, our CO_2 emission rate will decline even further in the future.

We have taken a leadership role in pursuing new ventures and testing and developing new technologies that show promise in achieving additional reductions in CO_2 emissions. These include:

- Sales of over 1 million MWH per year of wind generation.
- Testing of CO_2 sequestration to gain a better understanding of the potential for geological storage of CO_2.
- Supporting afforestation growing forests on non-forested land and other efforts designed to remove CO_2 from the environment.
- Reducing emissions of SF_6 (sulfur hexafluoride) by nearly 15 metric tons, resulting in an equivalent reduction of nearly 315,000 metric tons of CO_2, through the EPA s SF6 Emissions Reduction Partnership for Electric Power Systems.
- Supporting research to develop and evaluate cost effective sorbent materials for CO_2 capture including work by Powerspan at the Burger Plant, The University of Akron and the EPRI.

We remain actively engaged in the federal and state debate over future environmental requirements and legislation, especially those dealing with global climate change, hazardous air pollutants, coal combustion residues and water effluent discharges. We are committed to working with policy makers and regulators to develop fair and reasonable requirements, with the goal of reducing emissions while minimizing the economic impact on our customers. Due to the significant uncertainty as to the final form or timing of any such legislation and regulation at both the federal and state levels, we are unable to determine the potential impact and risks associated with future 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. We are testing the world s largest utility-scale fuel cell system at our Eastlake power plant to determine its feasibility for augmenting generating capacity during summer peak-use periods. 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. FirstEnergy s EasyGreen® load-management program utilizes two-way communication capability with customers non-critical equipment such as air conditioners in New Jersey and Pennsylvania to help manage peak loading on the electric distribution system. FirstEnergy has also made an online interactive energy efficiency tool, Home Energy Analyzer, available for its customers to help achieve electricity use-reduction goals.

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;
- financial derivatives reforms could increase our liquidity needs and collateral costs;
- 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 the 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 economic uncertainty 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;
our pending merger with Allegheny may not achieve its intended results;
upon consummation of the pending merger we will be subject to business uncertainties that could adversely affect our financial results;

once the pending merger is closed the combined company will have a higher percentage of coal-fired generation capacity compared to FirstEnergy s previous generation mix. As a result, FirstEnergy may be exposed to greater risk from regulations of coal and coal combustion by-products than it faced prior to the merger;
complex and changing government regulations could have a negative impact on our results of operations;
regulatory changes in the electric industry, including a reversal, discontinuance or delay of the present trend toward competitive markets, could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
the prospect of rising rates could prompt legislative or regulatory action to restrict or control such rate increases; this in turn could create uncertainty affecting planning, costs and results of operations and may adversely affect the utilities ability to recover their costs, maintain adequate liquidity and address capital requirements;
our profitability is impacted by our affiliated companies continued authorization to sell power at market-based rates;
there are uncertainties relating to our participation in RTOs;
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;
our business and activities are subject to extensive environmental requirements and could be adversely affected by such requirements;
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;
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 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; 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 FirstEnergy s business segments. A reconciliation of segment financial results is provided in Note 15 to the consolidated financial statements. Earnings available to FirstEnergy by major business segment were as follows:

				Increase (Decrease)	
	2010	**2009**	**2008**	**2010 vs 2009**	**2009 vs 2008**
	(In millions, except per share data)				
Earnings (Loss) By Business Segment:					
Energy delivery services	$ 607	$ 435	$ 916	$ 172	$ (481)
Competitive energy services	258	517	472	(259)	45
Other and reconciling adjustments*	(81)	54	(46)	(135)	100
Total	$ 784	$ 1,006	$ 1,342	$ (222)	$ (336)
Basic Earnings Per Share	$ 2.58	$ 3.31	$ 4.41	$ (0.73)	$ (1.10)
Diluted Earnings Per Share	$ 2.57	$ 3.29	$ 4.38	$ (0.72)	$ (1.09)

* Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses, noncontrolling interests and the elimination of intersegment transactions.

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Summary of Results of Operations 2010 Compared with 2009

Financial results for FirstEnergy s major business segments in 2010 and 2009 were as follows:

2010 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 9,271	$ 3,252	$	$ 12,523
Other	542	292	(92)	742
Internal*	139	2,301	(2,366)	74
Total Revenues	9,952	5,845	(2,458)	13,339
Expenses:				
Fuel		1,440	(8)	1,432
Purchased power	5,266	1,724	(2,366)	4,624
Other operating expenses	1,492	1,436	(78)	2,850
Provision for depreciation	451	254	41	746
Amortization of regulatory assets	722			722
Deferral of new regulatory assets				
Impairment of long lived assets		384		384
General taxes	653	113	10	776
Total Expenses	8,584	5,351	(2,401)	11,534
Operating Income	1,368	494	(57)	1,805
Other Income (Expense):				
Investment income	102	51	(36)	117
Interest expense	(496)	(221)	(128)	(845)
Capitalized interest	5	92	68	165
Total Other Expense	(389)	(78)	(96)	(563)
Income Before Income Taxes	979	416	(153)	1,242
Income taxes	372	158	(48)	482
Net Income (Loss)	607	258	(105)	760
Loss attributable to noncontrolling interest			(24)	(24)
Earnings available to FirstEnergy Corp.	$ 607	$ 258	$ (81)	$ 784

*

Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

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	447	(82)	924
Internal*		2,843	(2,826)	17
Total Revenues	11,144	4,737	(2,908)	12,973
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)
Impairment of long lived assets		6		6
General taxes	641	108	4	753
Total Expenses	10,089	3,890	(2,885)	11,094
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
Loss attributable to noncontrolling interest			(16)	(16)
Earnings available to FirstEnergy Corp.	$ 435	$ 517	$ 54	$ 1,006

* Under the accounting standard for the effects of certain types of regulation, Internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

Changes Between 2010 and 2009 Financial Results Increase (Decrease)	**Energy Delivery Services**	**Competitive Energy Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenues:				
External				
Electric	$ (1,314)	$ 1,805	$	$ 491
Other	(17)	(155)	(10)	(182)
Internal*	139	(542)	460	57
Total Revenues	(1,192)	1,108	450	366
Expenses:				
Fuel		287	(8)	279
Purchased power	(1,294)	728	460	(106)
Other operating expenses	68	79	6	153
Provision for depreciation	6	(16)	20	10
Amortization of regulatory assets	(433)			(433)
Deferral of new regulatory assets	136			136
Impairment of long lived assets		378		378
General taxes	12	5	6	23
Total Expenses	(1,505)	1,461	484	440
Operating Income	313	(353)	(34)	(74)
Other Income (Expense):				
Investment income	(37)	(70)	20	(87)
Interest expense	(24)	(55)	212	133
Capitalized interest	2	32	1	35
Total Other Expense	(59)	(93)	233	81
Income Before Income Taxes	254	(446)	199	7
Income taxes	82	(187)	342	237
Net Income	172	(259)	(143)	(230)
Loss attributable to noncontrolling interest			(8)	(8)
Earnings available to FirstEnergy Corp.	$ 172	$ (259)	$ (135)	$ (222)

* Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

Energy Delivery Services 2010 Compared to 2009

Net income increased $172 million to $607 million in 2010 compared to $435 million in 2009, primarily due to CEI s $216 million regulatory asset impairment in 2009, partially offset by increases in other operating expenses. Lower generation revenues were offset by lower purchased power expenses.

Revenues

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	**2010**	**2009**	**Increase (Decrease)**
		(In millions)	
Distribution services	$ 3,629	$ 3,419	$ 210
Generation sales:			
Retail	4,456	5,764	(1,308)
Wholesale	841	752	89
Total generation sales	5,297	6,516	(1,219)
Transmission	833	1,028	(195)
Other	193	181	12
Total Revenues	$ 9,952	$ 11,144	$ (1,192)

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The increase in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	
Residential	5.9%
Commercial	2.8%
Industrial	8.4%
Total Distribution KWH Deliveries	5.6%

Higher deliveries to residential and commercial customers reflect increased weather-related usage due to a 70% increase in cooling degree days in 2010 compared to 2009, partially offset by a 4% decrease in heating degree days for the same period. In the industrial sector, KWH deliveries increased primarily to major automotive customers (16%), refinery customers (7%) and steel customers (38%). The increase in distribution service revenues also reflects the Pennsylvania Companies recovery of the Pennsylvania EE&C as approved by the PPUC in March 2010 and the accelerated recovery of deferred distribution costs in Ohio, partially offset by a reduction in the transition rate for CEI effective June 1, 2009.

The following table summarizes the price and volume factors contributing to the $1.2 billion decrease in generation revenues in 2010 compared to 2009:

Source of Change in Generation Revenues	**Increase (Decrease)** *(In millions)*
Retail:	
Effect of 24.9% decrease in sales volumes	$ (1,438)
Change in prices	130
	(1,308)
Wholesale:	
Effect of 8.4% decrease in sales volumes	(64)
Change in prices	153
	89
Net Decrease in Generation Revenues	$ (1,219)

The decrease in retail generation sales volumes was primarily due to an increase in customer shopping in the Ohio Companies service territories. Total generation KWH provided by alternative suppliers as a percentage of total KWH deliveries by the Ohio Companies increased to 62% in 2010 from 17% in 2009. The decrease in volumes was partially offset by increases in generation revenues due to higher rates from the May 2009 Ohio CBP that include the recovery of transmission costs.

The increase in wholesale generation revenues reflected higher prices and increased capacity sales for Met-Ed and Penelec in the PJM market.

Transmission revenues decreased $195 million primarily due to the termination of the Ohio Companies transmission tariff effective June 1, 2009; transmission costs are now a component of the cost of generation established under the May 2009 Ohio CBP.

Expenses

Total expenses decreased by $1.5 billion due to the following:

Purchased power costs were $1.3 billion lower in 2010, largely due to lower volume requirements. The decrease in volumes from non-affiliates resulted principally from the termination of a third-party supply contract for Met-Ed and Penelec in January 2010 and from the increase in customer shopping in the Ohio Companies service territories. The decrease in purchases from FES also resulted from the increase in customer shopping in Ohio.

An increase in purchased power unit costs from non-affiliates in 2010 resulted from higher capacity prices in the PJM market for Met-Ed and Penelec. A decrease in unit costs for purchases from FES was principally due to the lower weighted average unit price per KWH established under the May 2009 CBP auction for the Ohio Companies effective June 1, 2009.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 619
Change due to decreased volumes	(1,489)
	(870)
Purchases from FES:	
Change due to decreased unit costs	(257)
Change due to decreased volumes	(250)
	(507)
Decrease in costs deferred	83
Net Decrease in Purchased Power Costs	$ (1,294)

Transmission expenses increased $70 million primarily due to higher PJM network transmission expenses and congestion costs for Met-Ed and Penelec, partially offset by lower MISO network transmission expenses that are reflected in the generation rate established under the May 2009 Ohio CBP. Met-Ed and Penelec defer or amortize the difference between revenues from their transmission rider and transmission costs incurred with no material effect on earnings.

Energy efficiency program costs, which are also recovered through rates, increased $41 million in 2010 compared to 2009.

Labor and employee benefit expenses decreased by $34 million due to lower pension and OPEB expenses, lower payroll costs resulting from staffing reductions implemented in 2009, and restructuring expenses recognized in 2009.

Expenses for economic development commitments related to the Ohio Companies ESP were lower by $11 million in 2010 compared to 2009.

Depreciation expense increased $6 million due to property additions since 2009.

Amortization of regulatory assets decreased $433 million due primarily to the absence of the $216 million impairment of CEI s regulatory assets in 2009, reduced net MISO and PJM transmission cost amortization and reduced CTC amortization for Met-Ed and Penelec, partially offset by increased amortization associated with the accelerated recovery of deferred distribution costs in Ohio and a $35 million regulatory asset impairment in 2010 associated with the Ohio Companies ESP.

The deferral of new regulatory assets decreased $136 million in 2010 due to CEI s purchased power cost deferrals that ended in early 2009.

General taxes increased $12 million principally due to a benefit relating to Ohio KWH excise taxes that was recognized in 2009 and applicable to prior years.

Other Expense

Other expense increased $59 million in 2010 compared to 2009 primarily due to lower nuclear decommissioning trust investment income ($37 million) and higher net interest expense associated with debt issuances by the Utilities during 2009 ($22 million).

Competitive Energy Services 2010 Compared to 2009

Net income decreased to $258 million in 2010 compared to $517 million in 2009. The decrease in net income was primarily due to $384 million of impairment charges ($240 million net of tax) in 2010. In addition, FES sold a 6.65%

participation interest in OVEC in 2010 compared to a 9% interest in 2009, accounting for $105 million of the reduction in net income. Investment income from nuclear decommissioning trusts was also lower in 2010. These reductions were partially offset by an increase in sales margins.

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Revenues

Total revenues increased $1,108 million in 2010 compared to the same period in 2009 primarily due to an increase in direct and government aggregation sales and sales of RECs, partially offset by decreases in POLR sales to the Ohio Companies, other wholesale sales and the reduced OVEC participation interest sale in 2010.

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

Revenues by Type of Service	2010	2009	Increase (Decrease)
		(In millions)	
Direct and Government Aggregation	$ 2,494	$ 779	$ 1,715
POLR	2,436	2,863	(427)
Wholesale	550	632	(82)
Transmission	77	73	4
RECs	74	17	57
Sale of OVEC participation interest	85	252	(167)
Other	129	121	8
Total Revenues	$ 5,845	$ 4,737	$ 1,108

The increase in direct and government aggregation revenues of $1.7 billion resulted from increased revenue from the acquisition of new commercial and industrial customers as well as from new government aggregation contracts with communities in Ohio that provide generation to 1.5 million residential and small commercial customers at the end of 2010 compared to approximately 600,000 customers at the end of 2009. Increases in direct sales were partially offset by lower unit prices. Sales to residential and small commercial customers were also bolstered by summer weather in the delivery area that was significantly warmer than in 2009.

The decrease in POLR revenues of $427 million was due to lower sales volumes and lower unit prices to the Ohio Companies, partially offset by increased sales volumes and higher unit prices to the Pennsylvania Companies. The lower sales volumes and unit prices to the Ohio Companies in 2010 reflected the results of the May 2009 CBP. The increased revenues to the Pennsylvania Companies resulted from FES supplying Met-Ed and Penelec with volumes previously supplied through a third-party contract and at prices that were slightly higher than in 2009.

Other wholesale revenues decreased $82 million due to reduced volumes, partially offset by higher prices. Lower sales volumes in MISO were due to available capacity serving increased retail sales in Ohio partially offset by increased sales under bilateral agreements in PJM.

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Direct and Government Aggregation	Increase (Decrease)
	(In millions)
Direct Sales:	
Effect of increase in sales volumes	$ 1,083
Change in prices	(82)
	1,001
Government Aggregation:	
Effect of increase in sales volumes	704
Change in prices	10

		714
Net Increase in Direct and Government Aggregation Revenues	$	1,715

Source of Change in Wholesale Revenues	Increase Decrease (In millions)
POLR:	
Effect of 5.3% decrease in sales volumes	$ (153)
Change in prices	(274)
	(427)
Other Wholesale:	
Effect of 26.5% decrease in sales volumes	(105)
Change in prices	23
	(82)
Net Decrease in Wholesale Revenues	$ (509)

Expenses

Total expenses increased $1.5 billion in 2010 due to the following factors:

Fuel costs increased $287 million in 2010 compared to 2009 primarily due to increased volumes consumed ($217 million) and higher unit prices ($70 million). The higher volumes consumed in 2010 were due to increased sales to direct and government aggregation customers, improved economic conditions and improved generating unit availability. The increase in unit prices was due primarily to increased coal transportation costs and to higher nuclear fuel unit prices following the refueling outages that occurred in 2009 and 2010.

Purchased power costs increased $728 million. Increased volumes purchased primarily relate to the assumption of a 1,300 MW third party contract from Met-Ed and Penelec.

Fossil operating costs decreased $12 million due primarily to lower labor and professional and contractor costs, which were partially offset by reduced gains from the sale of emission allowances and excess coal.

Nuclear operating costs decreased $21 million due primarily to lower labor, consulting and contractor costs partially offset by increased nuclear property insurance and employee benefit costs. The year 2010 had one less refueling outage and fewer extended outages than the same period of 2009.

Transmission expenses increased $25 million due primarily to increased costs in MISO of $170 million from higher network, ancillary and congestion costs, partially offset by lower PJM transmission expenses of $145 million due to lower congestion costs.

Depreciation expense decreased $16 million principally due to reduced depreciable property associated with the impairments described below and the sale of the Sumpter plant in early 2010.

General taxes increased $5 million due to an increase in revenue-related taxes.

Other expenses increased $465 million primarily due to a $384 million impairment charge ($240 million net of tax) related to operational changes at certain smaller coal-fired units in response to the continued slow economy, lower demand for electricity and uncertainty related to proposed new federal environmental regulations. Expenses were also increased due to the significant growth in FES retail business professional and contractor expenses, billings from affiliated service companies, uncollectible customer accounts and agent fees.

Other Expense

Total other expense in 2010 was $93 million higher than the same period in 2009, primarily due to a decrease in nuclear decommissioning trust investment income ($66) million and a $23 million increase in net interest expense from new long-term debt issued in late 2009 combined with the restructuring of outstanding PCRBs that occurred throughout 2009 and 2010.

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Other 2010 Compared to 2009

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $135 million decrease in earnings available to FirstEnergy in 2010 compared to 2009. The decrease resulted primarily from increased income tax expense ($342 million) due in part to the absence of favorable tax settlements that occurred in 2009 ($200 million), partially offset by the absence of 2009 debt retirement costs in connection with the tender offer for holding company debt ($90 million), decreased interest expense associated with the debt retirement ($53 million), increased investment income ($20 million) and decreased depreciation ($20 million).

Summary of Results of Operations 2009 Compared with 2008

Financial results for FirstEnergy s major business segments in 2009 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	447	(82)	924
Internal*		2,843	(2,826)	17
Total Revenues	11,144	4,737	(2,908)	12,973
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)
Impairment of long lived assets		6		6
General taxes	641	108	4	753
Total Expenses	10,089	3,890	(2,885)	11,094
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 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
Loss attributable to noncontrolling interest						(16)		(16)
Earnings available to FirstEnergy Corp.	$	435	$	517	$	54	$	1,006

* Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

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	1,053			1,053
Deferral of new regulatory assets	(316)			(316)
Impairment of long lived assets				
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
Loss attributable to noncontrolling interest			(3)	(3)
Earnings available to FirstEnergy Corp.	$ 916	$ 472	$ (46)	$ 1,342

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Changes Between 2009 and 2008 Financial Results Increase (Decrease)	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ (775)	$ 114	$	$ (661)
Other	(149)	209	(70)	(10)
Internal*		(125)	142	17
Total Revenues	(924)	198	72	(654)
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
Impairment of long lived assets		6		6
General taxes	(5)	(1)	(19)	(25)
Total Expenses	(215)	279	162	226
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 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)
Loss attributable to noncontrolling interest			(13)	(13)
Earnings available to FirstEnergy Corp.	$ (481)	$ 45	$ 100	$ (336)

* Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

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	**2010**	**2009**	**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)

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The decrease in distribution deliveries by customer class is 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:

Source 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 transmission costs became a component of 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.

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Revenues

Total revenues increased $198 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	122	88	34
Total Revenues	$ 4,737	$ 4,539	$ 198

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

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Source of Change in Affiliated Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of 36.3% decrease in sales volumes	$ (837)
Change in prices	645
	(192)
Wholesale:	
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 $279 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 $78 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.

POSTRETIREMENT BENEFITS

FirstEnergy provides 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. 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. Recovering market conditions and greater returns on higher asset levels decreased postretirement benefit expense in 2010, partially offset by a full year of realization on the reduction in benefit liability resulting from the OPEB plan amendment in 2009. Pension and OPEB expenses are included in various cost categories and have contributed to cost increases discussed above for 2010. 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, 2010:

Postretirement Benefits Expense (Credits)	**2010**	**2009**	**2008**
		(In millions)	
Pension	$ 174	$ 185	$ (23)
OPEB	(90)	(40)	(37)
Total	$ 84	$ 145	$ (60)

As of December 31, 2010, our pension plan was underfunded and we currently anticipate that an additional voluntary cash contribution of $250 million will be made in 2011.

The overall actual investment result during 2010 was a gain of 10% compared to an assumed 8.5% return. Based on discount rates of 5.50% for pension, 5.00% for OPEB and an estimated return on assets of 8.25%, our 2011 pre-tax net periodic postretirement benefit expense is expected to be approximately $92 million.

SUPPLY PLAN

Regulated Commodity Sourcing

The Utilities have a default service obligation to provide power 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 Companies 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 was secured through a FERC-approved agreement with FES through 2010, transitioning to a PPUC-approved competitive procurement process in 2011. If any supplier fails 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 POLR.

Unregulated Commodity Sourcing

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 13,236 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.

FES has retail and wholesale competitive load-serving obligations in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey serving both affiliated and non-affiliated companies. FES provides energy products and services to customers under various POLR, shopping, competitive-bid and non-affiliated contractual obligations. In 2010, FES generation was used to serve two primary obligations affiliated companies utilized approximately 43% of FES total generation and retail customers utilized approximately 43% of FES total generation. Geographically, approximately 60% of FES obligation is located in the MISO market area and 40% is located in the PJM market area.

CAPITAL RESOURCES AND LIQUIDITY

As of December 31, 2010, FirstEnergy had cash and cash equivalents of approximately $1 billion available to fund investments, operations and capital expenditures. To fund liquidity and capital requirements for 2011 and beyond, FirstEnergy may rely on internal and external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through issuances of debt and/or equity securities.

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FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2011, FirstEnergy expects to satisfy these requirements with a combination of internal cash from operations and external funds from the capital markets as market conditions warrant. FirstEnergy also expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy s ability to fund current liquidity and capital resource requirements. To mitigate risk, FirstEnergy s business model stresses financial discipline and a strong focus on execution. Major elements of this business model include the expectation of: projected cash from operations, opportunities for favorable long-term earnings growth as the transition to competitive generation markets is completed, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital expenditure program, adequately funded pension plan, minimal near-term maturities of existing long-term debt, commitment to a secure dividend (dividends declared from time to time on FirstEnergy s common stock during any annual period may in aggregate vary from the indicated amount due to circumstances considered by FirstEnergy s Board of Directors at the time of the actual declarations) and a successful merger integration.

As of December 31, 2010, FirstEnergy s net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings and the classification of certain variable interest rate PCRBs as currently payable long-term debt. Currently payable long-term debt as of December 31, 2010, included the following (in millions):

Currently Payable Long-term Debt		
PCRBs supported by bank LOCs [(1)]	$	827
FGCO and NGC PCRBs [(1)]		191
Penelec unsecured PCRBs		25
FirstEnergy Corp. unsecured note		250
NGC collateralized lease obligation bonds		50
Sinking fund requirements		33
FES term loan		100
Other obligations		10
	$	1,486

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

Short-Term Borrowings

FirstEnergy had approximately $700 million of short-term borrowings as of December 31, 2010 and $1.1 billion as of December 31, 2009. FirstEnergy s available liquidity as of January 31, 2011, is summarized in the following table:

Company	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy[(1)]	Revolving	Aug. 2012	$ 2,750	$ 2,245
FES	Term loan	Mar. 2011	100	
Ohio and Pennsylvania Companies	Receivables financing	Various[(2)]	395	237
		Subtotal	$ 3,245	$ 2,482
		Cash		668

Total	$	3,245	$	3,150

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) Ohio $250 million matures March 30, 2011; Pennsylvania $145 million matures June 17, 2011 with optional extension terms.

On October 22, 2010, Signal Peak and Global Rail, as borrowers, entered into a $350 million syndicated two-year senior secured term loan facility. The loan proceeds were used to repay $258 million of notes payable to FirstEnergy, including $9 million of interest and $63 million of bank loans that were scheduled to mature on November 16, 2010. Additional proceeds were used for general company purposes, including an $11 million repayment of a third-party seller s note. As discussed below under Guarantees and Other Assurances, FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership with FEV in the borrowers, have provided a guaranty of the borrowers obligations under the facility.

Revolving Credit Facility

FirstEnergy has 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. A total of 25 banks participate in the facility, with no one bank having more than 7.3% of the total commitment. 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, 2010:

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	34(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)	100

(1) No regulatory approvals, statutory or charter limitations applicable.

(2) Excluding amounts that 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, 2010, FirstEnergy s and its subsidiaries debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	60.6%
FES	52.6%
OE	54.1%

Penn	37.7%
CEI	57.1%
TE	57.6%
JCP&L	34.6%
Met-Ed	41.5%
Penelec	54.7%
ATSI	48.3%

As of December 31, 2010, FirstEnergy could issue additional debt of approximately $3.2 billion, or recognize a reduction in equity of approximately $1.7 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 2010 was 0.51% per annum for the regulated companies money pool and 0.60% per annum for the unregulated companies money pool.

Pollution Control Revenue Bonds

As of December 31, 2010, FirstEnergy s currently payable long-term debt included approximately $827 million (FES $778 million, Met-Ed $29 million and Penelec $20 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 FirstEnergy variable interest rate PCRBs were issued by the following banks as of December 31, 2010:

LOC Bank	Aggregate LOC Amount[(2)] *(In millions)*	LOC Termination Date	Reimbursements of LOC Draws Due
CitiBank N.A.	$ 166	June 2014	June 2014
The Bank of Nova Scotia	178	Beginning April 2011	Multiple dates[(3)]
The Royal Bank of Scotland	131	June 2012	6 months
Wachovia Bank	152	March 2014	March 2014
Barclays Bank[(1)]	208	April 2011	30 days
Total	$ 835		

(1) Supported by 13 participating banks, with no one bank having more than 22% of the total commitment.

(2) Includes approximately $8 million of applicable interest coverage.

(3) Shorter of 6 months or LOC termination date ($49 million) and shorter of one year or LOC termination date ($129 million).

On August 20, 2010, FES completed the remarketing of $250 million of PCRBs. Of the $250 million, $235 million of PCRBs were converted from a variable interest rate to a fixed interest rate. The remaining $15 million of PCRBs continue to bear a fixed interest rate. The interest rate conversion minimizes financial risk by converting the long-term debt into a fixed rate and, as a result, reducing exposure to variable interest rates over the short-term. These remarketings included two series: $235 million of PCRBs that now bears a per-annum rate of 2.25% and is subject to mandatory purchase on June 3, 2013; and $15 million of PCRBs that now bears a per-annum rate of 1.5% and is subject to mandatory purchase on June 1, 2011.

On October 1, 2010, FES completed the refinancing and remarketing of six series of PCRBs totaling $313 million. These PCRBs were converted from a variable interest rate to a fixed long term interest rate of 3.375% per annum and are subject to mandatory purchase on July 1, 2015.

On December 3, 2010, FES completed the remarketing of four series of PCRBs totaling $153 million and Penelec completed the remarketing of $25 million PCRBs. These PCRBs were converted from a variable interest rate to fixed interest rates ranging from 2.25% to 3.75% per annum.

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Long-Term Debt Capacity

As of December 31, 2010, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.4 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 $124 million and $26 million, respectively, as of December 31, 2010. As a result of the indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $394 million and $343 million, respectively, under provisions of their senior note indentures as of December 31, 2010.

Based upon FGCO s FMB indenture, net earnings and available bondable property additions as of December 31, 2010, FGCO had the capability to issue $1.7 billion of additional FMBs under the terms of that indenture. Based upon NGC s FMB indenture, net earnings and available bondable property additions, NGC had the capability to issue $695 million of additional FMBs as of December 31, 2010.

FirstEnergy s access to capital markets and costs of financing are influenced by the ratings of its securities. 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. Moody s and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010. On September 28, 2010, S&P issued a report reaffirming the ratings and stable outlook of FirstEnergy and its subsidiaries. Fitch revised its outlook on FirstEnergy and FES from stable to negative on December 15, 2010. The following table displays FirstEnergy s, FES and the Utilities securities ratings as of December 31, 2010:

	Senior Secured			Senior Unsecured		
Issuer	**S&P**	**Moody s**	**Fitch**	**S&P**	**Moody s**	**Fitch**
FirstEnergy Corp.				BB+	Baa3	BBB
FES				BBB-	Baa2	BBB
OE	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+			
CEI	BBB	Baa1	BBB	BBB-	Baa3	BBB-
TE	BBB	Baa1	BBB			
JCP&L				BBB-	Baa2	BBB+
Met-Ed	BBB	A3	BBB+	BBB-	Baa2	BBB
Penelec	BBB	A3	BBB+	BBB-	Baa2	BBB
ATSI				BBB-	Baa1	

Changes in Cash Position

As of December 31, 2010, FirstEnergy had $1 billion of cash and cash equivalents compared to $874 million as of December 31, 2009. As of December 31, 2010 and 2009, FirstEnergy had approximately $13 million and $12 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During 2010, FirstEnergy received $850 million of cash dividends from its subsidiaries and paid $670 million in cash dividends to common shareholders.

Cash Flows From Operating Activities

FirstEnergy s consolidated net cash from operating activities is provided primarily by its competitive energy services and energy delivery services businesses (see Results of Operations above). Net cash provided from operating activities was $3.1 billion in 2010, $2.5 billion in 2009 and $2.2 billion in 2008, as summarized in the following table:

Operating Cash Flows	**2010**	**2009**	**2008**
		(In millions)	
Net income	$ 760	$ 990	$ 1,339
Non-cash charges and other adjustments	2,309	2,281	1,405
Pension trust contribution		(500)	
Working capital and other	7	(306)	(520)
	$ 3,076	$ 2,465	$ 2,224

The increase in non-cash charges and other adjustments is primarily due to increased impairment charges on long lived assets ($378 million) combined with higher deferred income taxes and investment tax credits ($86 million), partially offset by lower net amortization of regulatory assets of ($297 million), including the impact of CEI s $216 million regulatory asset impairment recorded during the first quarter of 2009, and reduced charges relating to debt redemptions, primarily caused by a $142 million charge relating to debt redemptions during the third quarter of 2009.

The change in working capital and other is primarily due to cash proceeds of $129 million received on the termination of fixed-for-floating interest rate swaps during the second and third quarters of 2010, changes in investment securities of $121 million, increased accrued taxes and decreased prepayments primarily related to prepaid taxes ($279 million) and changes in uncertain tax positions ($176 million), partially offset by increased accounts receivable ($252 million), decreased accrued interest ($60 million) and increased cash collateral paid to third parties ($56 million).

Cash Flows From Financing Activities

In 2010, cash used for financing activities was $983 million compared to cash provided from financing activities of $49 million in 2009. The change was primarily due to reduced long-term debt issued in 2010 compared to 2009, partially offset by reduced long-term debt redemptions and reduced payments on short-term borrowings in 2010 as compared to 2009. The following table summarizes security issuances (net of any discounts) and redemptions:

Securities Issued or Redeemed	**2010**	**2009**	**2008**
		(In millions)	
New Issues			
First mortgage bonds	$	$ 398	$ 592
Pollution control notes	740	940	692
Senior secured notes	350	297	
Unsecured Notes	9	2,997	83
	$ 1,099	$ 4,632	$ 1,367
Redemptions			
First mortgage bonds	$ 32	$ 1	$ 126
Pollution control notes	741	884	698
Senior secured notes	141	217	35
Unsecured notes	101	1,508	175
	$ 1,015	$ 2,610	$ 1,034
Short-term borrowings, net	$ (378)	$ (1,246)	$ 1,494

Cash Flows From Investing Activities

Net cash flows used in investing activities resulted primarily from property additions. Additions for the energy delivery services segment primarily represent 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 2010, 2009 and 2008 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
		(In millions)		
Sources (Uses)				
2010				
Energy delivery services	$ (745)	$ 96	$ 13	$ (636)
Competitive energy services	(1,129)	(43)	(51)	(1,223)
Other	(24)	(7)	30	(1)
Inter-Segment reconciling items	(65)	(23)		(88)
Total	$ (1,963)	$ 23	$ (8)	$ (1,948)
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)

Net cash used for investing activities in 2010 decreased by $237 million compared to 2009. The decrease was principally due to a $240 million decrease in property additions (principally lower AQC system expenditures) and an increase in cash proceeds from the sale of assets of $96 million, partially offset by $113 million spent by FES in the customer acquisition process.

During 2011 through 2013 we anticipate average annual baseline capital expenditures of approximately $1.2 billion, exclusive of any additional opportunities or future mandated spending. This includes approximately $133 million, $300 million and $183 million in nuclear fuel expenditures for 2011, 2012 and 2013, respectively.

CONTRACTUAL OBLIGATIONS

As of December 31, 2010, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2011	2012-2013	2014-2015	Thereafter
			(In millions)		
Long-term debt	$ 13,928	$ 437	$ 995	$ 1,165	$ 11,331
Short-term borrowings	700	700			
Interest on long-term debt[(1)]	10,978	793	1,518	1,379	7,288

Operating leases[2]	3,314	213	477	506	2,118
Fuel and purchased power[3]	16,851	2,660	4,015	3,923	6,253
Capital expenditures	1,109	340	463	306	
Pension funding	1,076	250	74	543	209
Other[4]	112	31	14	14	53
Total	$ 48,068	$ 5,424	$ 7,556	$ 7,836	$ 27,252

(1) Interest on variable-rate debt based on rates as of December 31, 2010.

(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 9).

Excluded from the data shown above are estimates for the cash outlays stemming from the power purchase contracts entered into by the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. The exact amount of outlay will be determined by future customer behavior and consumption levels, but based on numerous planning assumptions management estimates an amount of $3.0 billion during 2011.

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GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon either FirstEnergy or its subsidiaries credit ratings.

As of December 31, 2010, FirstEnergy s maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $3.7 billion, as summarized below:

Guarantees and Other Assurances	**Maximum Exposure** *(In millions)*
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 300
LOC (long-term debt) Interest coverage[2]	2
FirstEnergy guarantee of OVEC obligations	300
Other[3]	227
	829
Subsidiaries Guarantees	
Energy and Energy-Related Contracts	54
LOC (long-term debt) Interest coverage[2]	3
FES guarantee of NGC s nuclear property insurance	70
FES guarantee of FGCO s sale and leaseback obligations	2,375
Other	2
	2,504
Surety Bonds	82
LOC (long-term debt) Interest coverage[2]	3
LOC (non-debt)[4][5]	339
	424
Total Guarantees and Other Assurances	$ 3,757

(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 $827 million is reflected in currently payable long-term debt on FirstEnergy s consolidated balance sheets.

(3) Includes guarantees of $15 million for nuclear decommissioning funding assurances, $161 million supporting OE s sale and leaseback arrangement, and $39 million for railcar leases.

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

(5) Includes approximately $130 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $42 million pledged in connection with the sale and leaseback of Perry by OE.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by its subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financings where the law might otherwise limit the counterparties claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy s guarantee enables the counterparty s legal claim to be satisfied by FirstEnergy s assets. FirstEnergy believes the likelihood is remote that such parental guarantees will increase amounts otherwise paid by FirstEnergy to meet its 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 or funding obligation or a material adverse event, the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2010, FirstEnergy s maximum exposure under these collateral provisions was $468 million, as shown below:

Collateral Provisions	FES	Utilities	Total
		(In millions)	
Credit rating downgrade to below investment grade [1]	$ 364	$ 65	$ 429
Material adverse event [2]	39		39
Total	$ 403	$ 65	$ 468

(1) Includes $137 million and $54 million that is also considered an acceleration of payment or funding obligation at FES and the Utilities, respectively.

(2) Includes $33 million that is also considered an acceleration of payment or funding obligation at FES.

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 $532 million consisting of $486 million due to a below investment grade credit rating (of which $224 million is related to an acceleration of payment or funding obligation) and $46 million due to material adverse event contractual clauses.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $82 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, FES contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES power portfolio as of December 31, 2010, and forward prices as of that date, FES has posted collateral of $185 million. 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 $28 million. Depending on the volume of forward contracts and future price movements, FES could be required to post 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, and FES guarantees 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.

As noted above under Capital Resources and Liquidity, FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC have provided a guaranty of the borrowers obligations under the $350 million syndicated two-year senior secured term loan facility entered into by Signal Peak and Global Rail. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the banks as collateral for the facility.

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on their 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 $1.6 billion as of December 31, 2010.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

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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.

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 6 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of December 31, 2010 are summarized by contract year in the following table:

Source of Information- Fair Value by Contract Year	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$	$	$	$	$	$	$
Other external sources[2]	(331)	(157)	(52)	(36)			(576)
Prices based on models					24	110	134
Total[3]	$ (331)	$ (157)	$ (52)	$ (36)	$ 24	$ 110	$ (442)

(1) Represents futures and options traded on the New York Mercantile Exchange.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

(3) Includes $335 million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would decrease net income by approximately $16 million ($10 million net of tax) during the next 12 months.

Interest Rate Swap Agreements Fair Value Hedges

FirstEnergy has used 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 were 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. As of December 31, 2010, no fixed-for-floating interest rate swap agreements were outstanding.

Total unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $124 million ($80 million net of tax) as of December 31, 2010. Based on current estimates, approximately $22 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled $12 million during 2010.

Interest Rate Risk

FirstEnergy s exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is 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, FirstEnergy s investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

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Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
					(In millions)			
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 80	$ 90	$ 101	$ 110	$ 76	$ 1,755	$ 2,212	$ 2,304
Average interest rate	8.4%	8%	8%	8%	8.1%	5.7%	6.2%	
Liabilities								
Long-term Debt:								
Fixed rate	$ 437	$ 94	$ 551	$ 536	$ 629	$ 10,504	$ 12,751	$ 13,668
Average interest rate	5.7%	7.8%	5.8%	5.4%	5.2%	6.3%	6.1%	
Variable rate		$ 350				$ 827	$ 1,177	$ 1,177
Average interest rate		2.5%				0.3%	1%	
Short-term Borrowings:	$ 700						$ 700	$ 700
Average interest rate	0.7%						0.7%	

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. As of December 31, 2010, approximately 28% of the pension plan assets are invested in equity securities, 50% invested in fixed income securities, 11% invested in absolute return strategies, 6% invested in real estate, 4% invested in private equity and 1% invested in cash. The plan is 83% funded on an accumulated benefit obligation basis as of December 31, 2010. A decline in the value of FirstEnergy s pension plan assets could result in additional funding requirements. FirstEnergy intends to voluntarily contribute $250 million to its pension plan in 2011.

Nuclear decommissioning trust funds have been established to satisfy NGC s and the Utilities nuclear decommissioning obligations. As of December 31, 2010, approximately 73% of the funds were invested in fixed income securities, 17% of the funds were invested in equity securities and 10% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,454 million, $337 million and $189 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $34 million reduction in fair value as of December 31, 2010. 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. A decline in the value of FirstEnergy s nuclear decommissioning trusts or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2010, $4 million was contributed to the OE and TE nuclear decommissioning trusts to comply with requirements under certain sale-leaseback transactions in which OE and TE continue as lessees, and $6 million was contributed to the JCP&L and Pennsylvania nuclear decommissioning trusts to comply with regulatory requirements. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

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CREDIT RISK

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

FirstEnergy maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FirstEnergy aggressively manages the quality of its portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of December 31, 2010, the largest credit concentration was with J.P. Morgan Chase & Co., which is currently rated investment grade, representing 10.9% of FirstEnergy s total approved credit risk composed of 3.3% for FES, 2.2% for JCP&L, 2.7% for Met-Ed and a combined 2.7% for OE, TE and CEI.

REGULATORY MATTERS

Regulatory assets that do not earn a current return totaled approximately $215 million as of December 31, 2010 (JCP&L $38 million, Met-Ed $131 million, Penelec $12 million, CEI $16 million and OE $18 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.

FirstEnergy and the Utilities prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred or accrued costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the recovery of costs or accrued liabilities that have been deferred because it is probable such amounts will be returned to customers through future regulated rates. The following table provides the balance of regulatory assets by Company as of December 31, 2010 and 2009, and changes during 2010:

Regulatory Assets	**December 31, 2010**	**December 31, 2009**	**Increase (Decrease)**
		(In millions)	
OE	$ 400	$ 465	$ (65)
CEI	370	546	(176)
TE	72	70	2
JCP&L	513	888	(375)
Met-Ed	296	357	(61)
Penelec	163	9	154
Other	12	21	(9)
Total	$ 1,826	$ 2,356	$ (530)

The following table provides information about the composition of regulatory assets as of December 31, 2010 and 2009 and the changes during 2010:

Regulatory Assets by Source	**December 31, 2010**	**December 31, 2009**	**Increase (Decrease)**
		(In millions)	
Regulatory transition costs	$ 770	$ 1,100	$ (330)
Customer shopping incentives		154	(154)
Customer receivables for future income taxes	326	329	(3)

Loss on reacquired debt	48	51	(3)
Employee postretirement benefits	16	23	(7)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(184)	(162)	(22)
Asset removal costs	(237)	(231)	(6)
MISO/PJM transmission costs	184	148	36
Deferred generation costs	386	369	17
Distribution costs	426	482	(56)
Other	91	93	(2)
Total	$ 1,826	$ 2,356	$ (530)

Ohio

The Ohio Companies operate under an ESP, which expires on May 31, 2011, that provides for generation supplied through a CBP. The ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the May 2009 CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million). Applications for rehearing of the PUCO order in the distribution case were filed by the Ohio Companies and one other party. The Ohio Companies raised numerous issues in their application for rehearing related to rate recovery of certain expenses, recovery of line extension costs, the level of rate of return and the amount of general plant balances. On February 2, 2011, the PUCO issued an Entry on Rehearing denying the applications for rehearing filed both by the Ohio Companies and by the other party.

On March 23, 2010, the Ohio Companies filed an application for a new ESP. The new ESP will go into effect on June 1, 2011 and conclude on May 31, 2014. The PUCO approved the new ESP on August 25, 2010 with certain modifications. The material terms of the new ESP include: a CBP similar to the one used in May 2009 and the one proposed in the October 2009 MRO filing; a 6% generation discount to certain low-income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (initial auctions scheduled for October 20, 2010 and January 25, 2011); no increase in base distribution rates through May 31, 2014; a load cap of no less than 80%, which also applies to any tranches assigned post auction; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. Rider DCR substitutes for Rider DSI which terminates under the current ESP. The Ohio Companies also agreed not to pay certain costs related to the companies   integration into PJM, for the longer of the five year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million dependent on the outcome of certain PJM proceedings, established a $12 million fund to assist low income customers over the term of the ESP, and agreed to additional energy efficiency benefits. Many of the existing riders approved in the previous ESP remain in effect, some with modifications. The new ESP resolved proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and the integration into PJM. FirstEnergy recorded approximately $39.5 million of regulatory asset impairments and expenses related to the ESP. On September 24, 2010, an application for rehearing was filed by the OCC and two other parties. On February 9, 2011, the PUCO issued an Entry on Rehearing denying the applications for rehearing.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to 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 0.75% reduction each year thereafter through 2018.

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 Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The Ohio Companies   three year portfolio plan is still awaiting decision from the PUCO, which is delaying the launch of the programs described in the plan. As a result, the Ohio Companies filed on January 11, 2011, a request for amendment of OE s 2010 energy efficiency and peak demand reduction benchmarks to levels actually achieved in 2010. Because the Commission indicated that it would revise all of the Ohio Companies   2010, 2011, and 2012 benchmarks when addressing the Ohio Companies   three year portfolio plan, and an order has yet to be issued on that plan, CEI and TE also requested a waiver of their respective yet-to-be defined 2010 energy efficiency benchmarks if and only to the degree one is deemed necessary to bring these companies into compliance with their 2010 energy efficiency obligations. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a penalty.

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 served in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs 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 were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On March 10, 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark, which application is still pending. In July 2010, the Ohio Companies initiated an additional RFP to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2010 and 2011. As a result of this RFP, contracts were executed in August 2010. On January 11, 2011, the Ohio Companies filed an application with the PUCO seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio due to the insufficient quantity of solar energy resources reasonably available in the market. The PUCO has not yet ruled on that application.

On February 12, 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. On March 3, 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect on March 17, 2010. On April 15, 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season, and charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect on May 21, 2010, and the proceeding remains open. The hearing in the matter is set to commence on February 16, 2011.

Pennsylvania

The PPUC adopted a Motion on January 28, 2010 and subsequently entered an Order on March 3, 2010 which denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. On March 18, 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. By Order entered March 25, 2010, the PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed the plan to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and the plan for the use of these funds to mitigate future generation rate increases commencing January 1, 2011. The PPUC approved this plan on June 7, 2010. On April 1, 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should prevail in the appeal and therefore expect to fully recover the approximately $252.7 million ($188.0 million for Met-Ed and $64.7 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011. The argument before the Commonwealth Court, *en banc*, was held on December 8, 2010.

On May 20, 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the period June 1, 2010 through December 31, 2010, including marginal transmission losses as approved by the PPUC, although the

recovery of marginal losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The TSC for Met-Ed s customers was increased to provide for full recovery by December 31, 2010.
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 through a prudent mix of long-term, short-term and spot market generation supply with a staggered procurement schedule that varies by customer class, using a descending clock auction. On August 12, 2009, the parties to the proceeding filed a settlement agreement of all but two issues, and the PPUC entered an Order approving the settlement and the generation procurement plan on November 6, 2009. Generation procurement began in January 2010.
On February 8, 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. On July 29, 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn s June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

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Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC on August 14, 2009. This plan proposed 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 of approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the SMIP as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; denying the recovery of interest through the automatic adjustment clause; providing for the recovery of reasonable and prudent costs net of resulting savings from installation and use of smart meters; and requiring that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the SMIP for the Pennsylvania Companies. The PPUC entered its Order on June 9, 2010, consistent with the Chairman s Motion. On June 24, 2010, Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC s Order regarding the future ability to include smart meter costs in base rates. On August 5, 2010, the PPUC granted in part the petition for reconsideration by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2010, the accumulated deferred cost balance was a credit of approximately $37 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. On February 10, 2011, the NJBPU approved a stipulation which allows the change in rates to become effective March 1, 2011.

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 estimated at $736 million (in 2003 dollars). 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 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. On April 16, 2010, the NJBPU issued an order indefinitely suspending the requirement of New Jersey utilities to submit Utility Master Plans until such time as the status of the EMP has been made clear. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their operations.

FERC Matters

Rates for 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 SECA) during a 16-month transition period. In 2005, the FERC set the SECA for hearing. The presiding ALJ 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 was subject to review and approval by the FERC. On May 21, 2010, FERC issued an order denying pending rehearing requests and an Order on Initial Decision which reversed the presiding ALJ s rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. The Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy s liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon, settlements were approved by FERC on November 23, 2010, and the relevant payments made. Rehearings remain pending in this proceeding.

PJM Transmission Rate

On April 19, 2007, 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, 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 based on the amount of load served in a transmission zone. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology (DFAX), which is generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities.

The FERC s Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision on August 6, 2009. The court affirmed FERC s ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500+ kV facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

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 and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM s filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain eastern utilities in PJM bearing the majority of their costs. Numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. FirstEnergy and a number of other utilities, industrial customers and state commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. FERC is expected to act by May 31, 2011.

RTO Realignment

On December 17, 2009, FERC issued an order approving, subject to certain future compliance filings, ATSI s withdrawal from MISO and integration into PJM. This move, which is expected to be effective on June 1, 2011, allows FirstEnergy to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy s transmission assets and operations are divided between PJM and MISO. The realignment will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. In the order, FERC approved FirstEnergy s proposal to use a FRR Plan to obtain capacity to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years.

FirstEnergy successfully conducted the FRR auctions on March 19, 2010. Moreover, the ATSI zone loads participated in the PJM base residual auction for the 2013 delivery year. Successful completion of these steps secured the capacity necessary for the ATSI footprint to meet PJM s capacity requirements. On August 25, 2010, the PUCO issued an order in the 2010 ESP Case approving a settlement that, among other things, called for the PUCO to withdraw its opposition to the RTO consolidation. In addition, the order approved a wholesale procurement process, and certain retail choice policies, that reflected ATSI s entry into PJM on June 1, 2011.

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. FirstEnergy expects ATSI to enter PJM on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. Additional FERC proceedings are either pending or expected in which the amount of exit fees, transmission cost allocations, and costs associated with long term firm transmission rights payable by the ATSI zone upon its withdrawal from the Midwest ISO will be determined. In addition, certain parties may protest other aspects of ATSI s integration into PJM, and certain of these matters remain outstanding and will be resolved in future FERC proceedings. The outcome of these proceedings cannot be predicted.

MISO Multi-Value Project Rule Proposal

On July 15, 2010, MISO and certain MISO transmission owners jointly filed with FERC their proposed cost allocation methodology for certain new transmission projects. The new transmission projects described as MVPs are a class of MTEP projects. The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be wheeled through the MISO as well as to energy transactions that source in the MISO but sink outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO s Board approved the first MVP project the Michigan Thumb Project. Under MISO s proposal, the costs of MVP projects approved by MISO s Board prior to the anticipated June 1, 2011 effective date of FirstEnergy s integration into PJM would continue to be allocated to FirstEnergy. MISO estimated that approximately $11 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

On September 10, 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO s proposal to allocate costs of MVP projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the beneficiary pays approach). FirstEnergy also argued that, in light of progress to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO s MVP proposal.

On December 16, 2010, FERC issued an order approving the MVP proposal without significant change. FERC s order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO s tariffs obligate ATSI to pay all charges that attach prior to ATSI s exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC s order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy filed for rehearing of FERC s order. In its rehearing request, the Company argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. FirstEnergy cannot predict the outcome of these proceedings at this time.

Sales to Affiliates

FES has received authorization from FERC to make wholesale power sales to the Utilities. FES actively participates in auctions conducted by or on behalf of the Utilities to obtain the power and related services necessary to meet the Utilities POLR obligations. Because of the merger with FirstEnergy, AS is considered an affiliate of the Utilities for purposes of FERC s affiliate restriction regulations. This requires AS to obtain prior FERC authorization to make sales to the Utilities when it successfully participates in the Utilities POLR auctions.

FES currently supplies the Ohio Companies with a portion of their capacity, energy, ancillary services and transmission under a Master SSO Supply Agreement for a two-year period ending May 31, 2011. FES won 51 tranches in a descending clock auction for POLR service administered by the Ohio Companies and their consultant, CRA International on May 13-14, 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 POLR load of the Ohio Companies until May 31, 2011.

On October 20, 2010, FES participated in a descending clock auction for POLR service administered by the Ohio Companies and their consultant, CRA International, for the following periods: June 1, 2011 through May 31, 2012; June 1, 2011, through May 31, 2013; and June 1, 2010 through May 31, 2014. The Ohio Companies offered 17, 17, and 16 tranches for these periods, respectively. FES won 10, 7, and 3 tranches, respectively, for these periods. On January 25, 2011, the Ohio Companies conducted a second auction offering the same product for identical time periods. FES won 3, 0, and 3 tranches, respectively, for these periods. FES entered into a Master SSO Supply Agreement to provide capacity, energy, ancillary services, and congestion costs to the Ohio Companies for the tranches won. Under the ESP in effect for these time periods, the Ohio Companies are responsible for payment of noncontrollable transmission costs billed by PJM for POLR service.

On October 18, 2010, FES participated in a descending clock auction for POLR service administered by both Met-Ed and Penelec and their consultant, National Economic Research Associates (NERA) for the following tranche products and delivery periods: Residential 5-month, Residential 24-month, Commercial 5-month, Commercial 12-month and Industrial 12-month. All 5-month delivery periods are from January 1, 2011 through May 31, 2011, all 12-month delivery periods are from June 1, 2011 through May 31, 2012 while all 24-month delivery periods are from June 1, 2011 through May 31, 2013. Met-Ed offered 7 Residential 5-month tranches, 4 Residential 24-month tranches, 6 Commercial 5-month tranches, 6 Commercial 12-month tranches and 1 Industrial tranche while Penelec offered 5 Residential 5-month tranches, 3 Residential 24-month tranches, 5 Commercial 5-month tranches, 5 Commercial 12-month tranches and 1 Industrial tranche.

For Met-Ed offerings, FES won 4 Residential 5-month tranches, 2 Residential 24-month tranches, 1 Commercial 5-month tranche, 1 Commercial 12-month tranche and zero Industrial tranches. For Penelec offerings, FES won 1 Residential 5-month tranche, 1 Residential 24-month tranche, zero Commercial 5-month tranches, zero Commercial 12-month tranches and zero Industrial tranches. FES entered into separate Supplier Master Agreements (SMA) to provide capacity, energy, ancillary services, and congestion costs with Met-Ed and Penelec for each product won. Under the terms and conditions of the SMA, Met-Ed and Penelec are responsible for payment of noncontrollable transmission costs billed by PJM.

On January 18 to 20, 2011 FES participated in a descending clock auction for POLR service administered by Met-Ed, Penelec, and Penn Power and their consultant, NERA for the following tranche products and delivery periods: Residential 12-month, Residential 24-month, Commercial 12-month and Industrial 12-month. All 12-month delivery periods are from June 1, 2011 through May 31, 2012 while all 24-month delivery periods are from June 1, 2011 through May 31, 2013. Met-Ed offered 3 Residential 12-month tranches, 4 Residential 24-month tranches, 6 Commercial 12-month tranches and 11 Industrial tranches. Penelec offered 3 Residential 12-month tranches, 2 Residential 24-month tranches, 5 Commercial 12-month tranches and 11 Industrial tranches. Penn Power offered 2 Residential 12-month tranches, 1 Residential 24-month tranche, 3 Commercial 12-month tranches and 3 Industrial tranches.

For Met-Ed offerings, FES won 1 Commercial 12-month tranche and zero for the remaining products. For Penelec and Penn Power offerings, FES won no tranches. FES entered into a SMA to provide capacity, energy, ancillary services, and congestion costs with Met-Ed for the product won. Under the terms and conditions of the SMA, Met-Ed is responsible for payment of noncontrollable transmission costs billed by PJM.

Reliability Initiatives

Federally-enforceable mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, FGCO, FENOC and ATSI. The NERC, as the ERO is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by the Reliability*First* Corporation.

FirstEnergy believes that it generally is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases self-reporting an item to Reliability*First*. Moreover, it is clear that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time; however, 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.

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 resulting in customers losing power for up to eleven hours. 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. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to Reliability*First* a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, Reliability*First* issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to Reliability*First* on September 27, 2010. At this time, FirstEnergy is unable to predict the outcome of this investigation.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy s earnings and competitive position to the extent that FirstEnergy 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.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) under the CAA by burning lower-sulfur fuel, combustion controls and post-combustion controls, generating more electricity from lower-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

The Sammis, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NOx and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement.

In July 2008, three 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. Two of these complaints also 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. FGCO believes the claims are without merit and intends to defend itself against the allegations made in those three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against GenOn Energy, Inc. (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999) and Met-Ed. Specifically, these suits allege that modifications at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR permitting in violation of the CAA s PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. In September 2009, 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. The parties dispute the scope of Met-Ed s indemnity obligation to and from Sithe Energy.

In January 2009, the EPA issued a NOV to GenOn alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, 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 permitting in violation of the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station containing in all material respects identical allegations as the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification that was required 60 days prior to filing a citizen suit under the CAA. In January, 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking damages based on alleged modifications at the Homer City Power Station between 1991 to 1994 without preconstruction NSR permitting in violation of the CAA s PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the State of New York intervened and have filed a separate complaint regarding the Homer City Station. Mission Energy Westside, Inc. is seeking indemnification from Penelec, the co-owner 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 Westside, Inc. is under dispute and Penelec is unable to predict the outcome of this matter.

In January 2011, a complaint was filed against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking damages based on the Homer City Station s air emissions. The complaint was also filed against the former co-owner, NYSEG and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. The complaint also seeks certification as a class action and to enjoin the Homer City Station from operating except in a safe, responsible, prudent and proper manner. Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint.

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. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake generating plant. FGCO intends to comply with the CAA, including the EPA s information requests, but, at this time, is unable to predict the outcome of this matter.

National Ambient Air Quality Standards

The EPA s CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. 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 opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the NOx 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. In July 2010, the EPA proposed the CATR to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management continues to assess the impact of these environmental proposals and other factors on FGCO s facilities, particularly on the operation of its smaller, non-supercritical units. In August 2010, for example, management decided to idle certain units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NOx emission caps under the EPA s CAIR program) and 15 tons per year by 2018. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups, 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. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. On January 20, 2011, the U.S. District Court for the District of Columbia denied a motion by the EPA for an extension of the deadline to issue final rules, ordering the EPA to issue such rules by February 21, 2011. The EPA also entered into a consent decree requiring it to propose

MACT regulations for mercury and other hazardous air pollutants from electric generating units by March 16, 2011, and to finalize the regulations by November 16, 2011. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. 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. 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. 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.

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. 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 concentrations of several key GHGs increase the threat of climate change and may be regulated as air pollutants under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s PSD program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A 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; include 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 establish 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.

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. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. 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. On December 6, 2010, the U.S. Supreme Court granted a writ of certiorari to the Second Circuit in *Connecticut v. AEP*. Briefing and oral argument are expected to be completed in early 2011 and a decision issued in or around June 2011. While FirstEnergy is not a party to this litigation, 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.

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 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). The EPA has taken the position 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 U.S. Supreme Court reversed one significant aspect of the Second Circuit 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. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant s water intake channel to divert fish away from the plant s water intake system. On November 19, 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. Depending on the results of such studies and the EPA s further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

In June 2008, the U.S. Attorney s Office in Cleveland, Ohio 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

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, 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 residuals, including whether they should be regulated as hazardous or non-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. On May 4, 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA s hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. FGCO s future cost of compliance with any coal combustion residuals 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 EPA or 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, 2010, 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 $104 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $32 million) have been accrued through December 31, 2010. Included in the total are accrued liabilities of approximately $64 million for environmental remediation of former MGPs and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L s territory. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court s decision decertifying the class. Plaintiffs have filed, and JCP&L has opposed, a motion for leave to appeal to the New Jersey Supreme Court. JCP&L is waiting for the Court s decision.

Litigation Relating to the Proposed Allegheny Merger

In connection with the proposed merger (Note 22), purported shareholders of Allegheny have filed putative shareholder class action and/or derivative lawsuits against Allegheny and its directors and certain officers, referred to as the Allegheny Energy defendants, FirstEnergy and Merger Sub. Four putative class action and derivative lawsuits were filed in the Circuit Court for Baltimore City, Maryland (Maryland Court). One was withdrawn. The Maryland Court has consolidated the remaining three cases under the caption: In re Allegheny Energy Shareholder and Derivative Litigation, C.A. No. 24-C-10-1301. Three shareholder lawsuits were filed in the Court of Common Pleas of Westmoreland County, Pennsylvania and the court has consolidated these actions under the caption: In re Allegheny Energy, Inc. Shareholder Class and Derivative, Litigation, Lead Case No. 1101 of 2010. One putative shareholder class action was filed in the U.S. District Court for the Western District of Pennsylvania and is captioned Louisiana Municipal Police Employees Retirement System v. Evanson, et al., C.A. No. 10-319 NBF. In summary, the lawsuits allege, among other things, that the Allegheny Energy directors breached their fiduciary duties by approving the merger agreement, and that Allegheny, FirstEnergy and Merger Sub aided and abetted in these alleged breaches of fiduciary duty. The complaints seek, among other things, jury trials, money damages and injunctive relief. While FirstEnergy believes the lawsuits are without merit and has defended vigorously against the claims, in order to avoid the costs associated with the litigation, the defendants have agreed to the terms of a disclosure-based settlement of all these shareholder lawsuits and have reached agreement with counsel for all of the plaintiffs concerning fee applications. Under the terms of the settlement, no payments are being made by FirstEnergy or Merger Sub. A formal stipulation of settlement was filed with the Maryland Court on October 18, 2010 and it was approved and became final on January 12, 2011. The separate Pennsylvania federal and state proceedings were dismissed on January 14, 2011 and January 18, 2011, respectively. The above shareholder actions have been fully and finally resolved.

Nuclear Plant Matters

During a planned refueling outage that began on February 28, 2010, FENOC conducted a non destructive examination and testing of the CRDM nozzles of the Davis-Besse reactor pressure vessel head. FENOC identified flaws in CRDM nozzles that required modification. The NRC was notified of these findings, along with federal, state and local officials. On March 17, 2010, the NRC sent a special inspection team to Davis-Besse to assess the adequacy of FENOC s identification, analyses and resolution of the CRDM nozzle flaws and to ensure acceptable modifications were made prior to placing the RPV head back in service. After successfully completing the modifications, FENOC committed to take a number of corrective actions including strengthening leakage monitoring procedures and shutting Davis-Besse down no later than October 1, 2011, to replace the reactor pressure vessel head with nozzles made of material less susceptible to primary water stress corrosion cracking, further enhancing the safe and reliable operations of the plant. On June 29, 2010, FENOC returned Davis-Besse to service. On September 9, 2010, the NRC held a public exit meeting describing the results of the NRC special inspection team inspection of FENOC s identification of the CRDM nozzles with flaws and the modifications to those nozzles. On October 22, 2010, the NRC issued its final report of the special inspection. The report contained three findings characterized as very low safety significance that were promptly corrected prior to plant operation.

On April 5, 2010, the Union of Concerned Scientists (UCS) requested that the NRC issue a Show Cause Order, or otherwise delay the restart of the Davis-Besse Nuclear Power Station until the NRC determines that adequate protection standards have been met and reasonable assurance exists that these standards will continue to be met after the plant s operation is resumed. By a letter dated July 13, 2010, the NRC denied UCS s request for immediate action because the NRC has conducted rigorous and independent assessments of returning the Davis-Besse reactor vessel head to service and its continued operation, and determined that it was safe for the plant to restart. The UCS petition was referred to a petition manager for further review. What additional actions, if any, that the NRC takes in response to the UCS request have not been determined.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2010, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. FirstEnergy provides an additional $15 million parental guarantee associated with the funding of decommissioning costs for these units. 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 could also affect the values of the nuclear decommissioning trusts. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated the decommissioning of FirstEnergy s nuclear facilities. As a result, FirstEnergy s decommissioning funding obligations are expected to increase. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

On August 27, 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station operating license for an additional twenty years, until 2037. On December 27 and 28, 2010, a group of petitioners filed a request for hearing contending that FENOC failed to adequately consider wind or solar generation, or some combination thereof, as an alternative to license extension at Davis-Besse. They further argued FENOC had failed to adequately assess the cost of a severe accident at Davis-Besse. FENOC and the NRC staff responded to this pleading on January 21, 2011, demonstrating that none of the petitioners arguments were admissible contentions under the National Environmental Policy Act or NRC regulations. An Atomic Safety and Licensing Board panel is expected to determine whether a hearing is necessary.

Ohio Legal Matters

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. On March 18, 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

Other Legal Matters

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

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of FirstEnergy assets are subject to specific risks and uncertainties and are regularly reviewed for impairment. FirstEnergy s more significant accounting policies are described below.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class.

Regulatory Accounting

FirstEnergy s energy delivery services segment is subject to regulation that sets the prices (rates) the Utilities are permitted to charge customers based on costs that the regulatory agencies determine the Utilities are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets based on anticipated future cash inflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Pension and Other Postretirement Benefits Accounting

FirstEnergy s reported costs of providing noncontributory qualified and non-qualified defined pension benefits and OPEB benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions FirstEnergy makes to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs.

In accordance with GAAP, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. GAAP delays recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants experience.

FirstEnergy recognizes the overfunded or underfunded status of the defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The underfunded status of FirstEnergy s qualified and non-qualified pension and OPEB plans at December 31, 2010 was $1.7 billion. FirstEnergy voluntarily intends to contribute $250 million to its pension plan in 2011.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed discount rates for pension were 5.50%, 6.00% and 7.00% for December 31, 2010, 2009 and 2008, respectively. The assumed discount rates for OPEB were 5.00%, 5.75% and 7.0% as of December 31, 2010, 2009 and 2008, respectively.

FirstEnergy s assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2010, FirstEnergy s qualified pension and OPEB plan assets earned $492 million or 10.1% compared to amounts earned of $570 million or 13.6% in 2009. The qualified pension and OPEB costs in 2010 and 2009 were computed using an assumed 8.5% and 9.0% rate of return, respectively, on plan assets which generated $397 million and $379 million of expected returns on plan assets, respectively. The expected return of pension and OPEB assets is based on the trusts asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension and OPEB cost, respectively.

FirstEnergy s qualified and non-qualified pension and OPEB net periodic benefit cost was $138 million in 2010 compared to $197 million in 2009 and credits of $116 million in 2008. FirstEnergy expects the 2011 qualified and non-qualified pension and OPEB costs (including amounts capitalized) to be $103 million.

On June 2, 2009, FirstEnergy amended the health care benefits plan for all employees and retirees eligible that participate in that plan. The amendment, which reduces future health care coverage subsidies paid by FirstEnergy on behalf of participants, triggered a remeasurement of FirstEnergy s other postretirement benefit plans as of May 31, 2009. On September 2, 2009, the Utilities and ATSI made a combined $500 million voluntary contribution to their qualified pension plan. Due to the significance of the voluntary contribution, FirstEnergy elected to remeasure the qualified pension plan as of August 31, 2009. In the third quarter of 2009, FirstEnergy also incurred a $13 million net postretirement benefit cost (including amounts capitalized) related to a liability created by the VERO offered by FirstEnergy to qualified employees. The special termination benefits of the VERO included additional health care coverage subsidies paid by FirstEnergy to those qualified employees who elected to retire. A total of 715 employees accepted the VERO.

Health care cost trends continue to increase and will affect future OPEB costs. The 2010 composite health care trend rate assumptions were approximately 8-9%, compared to 8.5-10% in 2009, gradually decreasing to 5% in later years. In determining FirstEnergy s trend rate assumptions, included are the specific provisions of FirstEnergy s health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy s health care plans, and projections of future medical trend rates. The effect on the pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	**Adverse Change**	**Pension**	**OPEB** *(In millions)*	**Total**
Discount rate	Decrease by 0.25%	$ 13	$ 1	$ 14
Long-term return on assets	Decrease by 0.25%	$ 12	$ 1	$ 13
Health care trend rate	Increase by 1%	N/A	$ 4	$ 4

Emission Allowances

FirstEnergy holds emission allowances for SO_2 and NO_X in order to comply with programs implemented by the EPA designed to regulate emissions of SO_2 and NO_X produced by power plants. Emission allowances are either granted by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at the lesser of weighted average cost or market value. Emission allowances eligible for use in future years are recorded as other investments. FirstEnergy recognizes emission allowance costs as fuel expense during the periods that emissions are produced by generating facilities. Excess emission allowances that are not needed to meet emission requirements may be sold and are reported as a reduction to other operating expenses.

Long-Lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such an asset may not be recoverable. The recoverability of a long-lived asset is measured by comparing the asset s carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted future cash flows of the long-lived asset, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Asset Retirement Obligations

FirstEnergy recognizes an ARO for the future decommissioning of FirstEnergy s nuclear power plants and future remediation of other environmental liabilities associated with long-lived assets. The ARO liability represents an estimate of the fair value of the current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants current license, settlement based on an extended license term and expected remediation dates.

Income Taxes

We record income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Company recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit s goodwill is less than the carrying value of its goodwill.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

See Note 16 to the consolidated financial statements for discussion of new accounting pronouncements.

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FIRSTENERGY SOLUTIONS CORP.
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FirstEnergy. FES provides energy-related products and services, and through its subsidiaries, FGCO and NGC, owns or leases and operates and maintains FirstEnergy s fossil and hydroelectric generation facilities, and owns FirstEnergy s nuclear generation facilities, respectively. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities.

FES revenues during 2010 were derived from sales to individual retail customers, sales to communities in the form of government aggregation programs, the sale of electricity to Met-Ed and Penelec to meet all of their POLR and default service requirements, and its participation in affiliated and non-affiliated POLR auctions. FES sales were primarily concentrated in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. Beginning in 2011, FES will not be required to supply Met-Ed and Penelec s POLR and default service requirements as Met-Ed and Penelec will procure power under their Default Service Plans in which full requirements products (energy, capacity, ancillary services and applicable transmission services) are procured through descending clock auctions.

The demand for electricity produced and sold by FES, along with the price of that electricity, is impacted by conditions in competitive power markets, global economic activity, economic activity in the Midwest and Mid-Atlantic regions and weather conditions.

For additional information with respect to FES, please see the information contained in FirstEnergy Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Regulatory Matters, Environmental Matters, Other Legal Proceedings and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased to $269 million in 2010 compared to $577 million in 2009. The decrease in net income was primarily due to $384 million of impairment charges ($240 million net of tax) in 2010. In addition, FES sold a 6.65% participation interest in OVEC in 2010 compared to a 9% interest in 2009, accounting for $105 million of the reduction in net income. Investment income from nuclear decommissioning trusts was also lower in 2010. These reductions were partially offset by an increase in sales margins.

Revenues

Excluding the impact of the OVEC sale in both years, total revenues increased $1,267 million in 2010 compared to the same period in 2009, primarily due to an increase in direct and government aggregation sales and sales of RECs, partially offset by decreases in POLR sales to the Ohio Companies and other wholesale sales.

The increase in revenues resulted from the following sources:

Revenues by Type of Service	2010	2009	Increase (Decrease)
		(In millions)	
Direct and Government Aggregation	$ 2,494	$ 779	$ 1,715
POLR	2,436	2,863	(427)
Other Wholesale	550	632	(82)
Transmission	77	73	4
RECs	74	17	57
Sale of OVEC participation interest	85	252	(167)
Other	112	112	
Total Revenues	**$ 5,828**	**$ 4,728**	**$ 1,100**

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Direct and government aggregation revenues increased by $1.7 billion due to the acquisition of new commercial and industrial customers as well as from new government aggregation contracts with communities in Ohio that provide generation to 1.5 million residential and small commercial customers at the end of 2010 compared to 600,000 of such customers at the end of 2009. Increases in direct sales were partially offset by lower unit prices. Sales to residential and small commercial customers were also bolstered by summer weather in the delivery area that was significantly warmer than in 2009.

The decrease in POLR revenues of $427 million was due to lower sales volumes and unit prices to the Ohio Companies, partially offset by increased sales volumes and higher unit prices to the Pennsylvania Companies. The lower sales volumes and unit prices to the Ohio Companies in 2010 reflected the results of the May 2009 CBP. The increased revenues to the Pennsylvania Companies resulted from FES supplying Met-Ed and Penelec with volumes previously supplied through a third-party contract and at prices that were slightly higher than in 2009.

Other wholesale revenues decreased $82 million due to reduced volumes, partially offset by higher prices. Lower sales volumes in MISO were due to available capacity serving increased retail sales in Ohio, partially offset by increased sales under bilateral agreements in PJM.

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Direct and Government Aggregation	**Increase (Decrease)** *(In millions)*
Direct Sales:	
Effect of increase in sales volumes	$ 1,083
Change in prices	(82)
	1,001
Government Aggregation	
Effect of increase in sales volumes	704
Change in prices	10
	714
Net Increase in Direct and Government Aggregation Revenues	$ 1,715

Source of Change in Wholesale Revenues	**Increase (Decrease)** *(In millions)*
POLR:	
Effect of decrease in sales volumes	$ (153)
Change in prices	(274)
	(427)
Other Wholesale:	
Effect of decrease in sales volumes	(105)
Change in prices	23

		(82)
Net Decrease in Wholesale Revenues	$	(509)

Expenses

Total expenses increased $1.5 billion in 2010 compared to 2009. The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2010 compared to 2009:

Source of Change in Fuel and Purchased Power	**Increase (Decrease)** ***(In millions)***
Fossil Fuel:	
Change due to increased unit costs	$ 34
Change due to volume consumed	207
	241
Nuclear Fuel:	
Change due to increased unit costs	29
Change due to volume consumed	5
	34
Non-affiliated Purchased Power:	
Power contract mark-to-market adjustment	(168)
Change due to decreased unit costs	(139)
Change due to volume purchased	896
	589
Affiliated Purchased Power:	
Change due to increased unit costs	101
Change due to volume purchased	47
	148
Net Increase in Fuel and Purchased Power Costs	**$ 1,012**

Fossil fuel costs increased $241 million in 2010 compared to 2009. Increased volumes consumed in 2010 were due to higher sales to direct and government aggregation customers as well as to improved economic conditions. The higher unit prices reflect higher coal transportation charges in 2010 compared to last year. Nuclear fuel costs increased $34 million primarily due to the replacement of nuclear fuel at higher unit costs following the refueling outages that occurred in 2009 and 2010.

Non-affiliated purchased power costs increased $589 million. Increased volumes purchased primarily relate to the assumption of a 1,300 MW third party contract from Met-Ed and Penelec. Affiliated purchased power increased $148 million primarily due to higher unit costs combined with higher volumes purchased from affiliated companies.

Other operating expenses increased $96 million in 2010 compared to 2009, primarily due to the significant growth in FES retail business. Costs increased for transmission expenses, contractor expenses, associated company billings from affiliated service companies, uncollectible customer accounts and agent fees. Those increases were partially offset by reduced generating plant operating costs due to lower labor and one less nuclear refueling outage in 2010.

In 2010 impairment charges of long-lived assets increased expenses by $384 million ($240 million net of tax) related to operational changes at certain smaller coal-fired units in response to the continued slow economy, lower demand for electricity as well as uncertainty related to proposed new federal environmental regulations.

Depreciation expense decreased $16 million principally due to reduced depreciable property associated with the impairments described above and sale of the Sumpter plant in early 2010.

General taxes increased $7 million due to sales taxes associated with increased revenues.

Other Expense

Total other expense in 2010 was $94 million higher than the same period in 2009, primarily due to a decrease in nuclear decommissioning trust investment income of $66 million and a $32 million increase in interest expense (net of capitalized interest) from new long-term debt issued in late 2009 combined with the restructuring of outstanding PCRBs that occurred throughout 2009 and 2010.

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Market Risk Information

FES uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FES 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, FES uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes.

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, FES relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FES uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 6 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of December 31, 2010 are summarized by contract year in the following table:

Source of Information- Fair Value by Contract Year	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$	$	$	$	$	$	$
Other external sources[2]	(115)	6	4	7			(98)
Prices based on models						(9)	(9)
Total	$ (115)	$ 6	$ 4	$ 7	$	$ (9)	$ (107)

(1) Represents futures and options traded on the New York Mercantile Exchange.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would decrease net income by approximately $16 million ($10 million net of tax) during the next 12 months.

Interest Rate Risk

FES exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for FES investment portfolio and debt obligations.

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Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$ 994	$ 994	$ 994
Average interest rate						10.1%	10.1%	
Liabilities								
Long-term Debt:								
Fixed rate	$ 158	$ 68	$ 75	$ 99	$ 450	$ 2,650	$ 3,500	$ 3,624
Average interest rate	4.6%	9%	9%	7.3%	5.1%	5.2%	5.3%	
Variable rate						$ 779	$ 779	$ 779
Average interest rate						0.3%	0.3%	
Short-term Borrowings:	$ 12						$ 12	$ 12
Average interest rate	0.6%						0.6%	

Equity Price Risk

Nuclear decommissioning trust funds have been established to satisfy NGC s nuclear decommissioning obligations. Included in FES s nuclear decommissioning trust are fixed income and short-term investments carried at a market value of approximately $1,139 million as of December 31, 2010. NGC recognizes in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts as other-than-temporary impairments. A decline in the value of the nuclear decommissioning trusts or a significant escalation in estimated decommissioning costs could result in additional funding requirements. FES continues to evaluate the status of its funding obligations for the decommissioning of 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. FES engages in transactions for the purchase and sale of commodities including gas, electricity, coal and emission allowances. These transactions are often with major energy companies within the industry.

FES maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FES aggressively manages the quality of its portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of December 31, 2010, the largest credit concentration was with J.P. Morgan Chase & Co., which is currently rated investment grade, representing 3.3% of FES total approved credit risk.

OHIO EDISON COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

OE is a wholly owned electric utility subsidiary of FirstEnergy. OE and its wholly owned subsidiary, Penn, conduct business in portions of Ohio and Pennsylvania, providing regulated electric distribution services. They provide generation services to those franchise customers electing to retain OE and Penn as their power supplier.

For additional information with respect to OE, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent increased by $35 million in 2010 compared to 2009. The increase primarily resulted from lower purchased power costs and other operating costs, partially offset by lower revenues and investment income.

Revenues

Revenues decreased $681 million, or 27%, in 2010 compared to 2009 due primarily to a decrease in generation revenues.

Distribution revenues increased $6 million in 2010 compared to 2009, due to higher residential revenues, partially offset by lower commercial and industrial revenues. Commercial and industrial revenues were primarily impacted by lower average unit prices, resulting from lower transmission rates in 2010. Residential distribution revenues increased due to higher average unit prices resulting from the 2009 ESP and higher KWH deliveries resulting from the warmer conditions (cooling degree days increased 88% in OE s service territory). Increased industrial deliveries were the result of higher KWH deliveries to major steel customers and automotive customers, reflecting improving economic conditions.

Changes in distribution KWH deliveries and revenues in 2010 compared to 2009 are summarized in the following tables:

Distribution KWH Deliveries	**Increase**
Residential	5.5%
Commercial	2.6%
Industrial	9.5%
Increase in Distribution Deliveries	**5.8%**

Distribution Revenues	**Increase (Decrease)** *(In millions)*
Residential	$ 33
Commercial	(7)
Industrial	(20)
Net Increase in Distribution Revenues	**$ 6**

Retail generation revenues decreased $680 million primarily due to lower KWH sales in all customer classes. Lower KWH sales resulted principally from a 36% increase in customer shopping in 2010. That sales reduction was partially offset by increased weather-related usage in 2010 as described above. Lower average unit pricing also contributed to the decrease as lower unit prices in the residential class were partially offset by higher unit prices in the commercial and industrial classes.

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Changes in retail generation KWH sales and revenues in 2010 compared to 2009 are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(26.0)%
Commercial	(58.0)%
Industrial	(58.2)%
Decrease in Retail Generation Sales	**(43.3)%**

Retail Generation Revenues		Decrease
	(In millions)	
Residential	$	(216)
Commercial		(266)
Industrial		(198)
Decrease in Retail Generation Revenues	**$**	**(680)**

Expenses

Total expenses decreased $752 million in 2010 compared to 2009. The following table presents changes from the prior period by expense category:

Expenses Changes		Increase (Decrease)
	(In millions)	
Purchased power costs	$	(635)
Other operating expenses		(97)
Provision for depreciation		(1)
Amortization of regulatory assets, net		(31)
General taxes		12
Net Decrease in Expenses	**$**	**(752)**

Purchased power costs decreased in 2010 compared to 2009, primarily due to lower KWH purchases resulting from reduced requirements in 2010 and slightly lower unit costs. The decrease in other operating costs for 2010 was primarily due to lower MISO transmission expenses ($48 million) (assumed by third party suppliers beginning June 1, 2009), the absence in 2010 of costs associated with regulatory obligations for economic development and energy efficiency programs under OE s 2009 ESP ($18 million) and decreased labor expenses ($12 million). The amortization of regulatory assets decreased primarily due to lower MISO transmission cost amortization, partially offset by increased recovery of other regulatory assets. The increase in general taxes was primarily due to higher Ohio KWH taxes in 2010 as compared to 2009 and a $7.1 million Ohio KWH tax adjustment recognized in 2009 related to prior periods.

Other Expense

Other expense increased $21 million in 2010 compared to 2009, primarily due to lower nuclear decommissioning trust investment income.

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Interest Rate Risk

OE s exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for OE s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 28	$ 31	$ 37	$ 42	$ 37	$ 138	$ 313	$ 365
Average interest rate	8.7%	8.7%	8.8%	8.8%	8.9%	4%	6.7%	
Liabilities								
Long-term Debt:								
Fixed rate						$ 1,159	$ 1,159	$ 1,321
Average interest rate						6.9%	6.9%	
Short-term Borrowings:	$ 142						$ 142	$ 142
Average interest rate	0.5%						0.5%	

Equity Price Risk

Nuclear decommissioning trust funds have been established to satisfy nuclear decommissioning obligations. Included in OE s nuclear decommissioning trust are fixed income and short-term investments carried at a market value of approximately $126 million as of December 31, 2010. OE recognizes in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trust as other-than-temporary impairments. A decline in the value of the nuclear decommissioning trust or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2010, $4 million was contributed to the OE and TE nuclear decommissioning trusts to comply with requirements under certain sale-leaseback transactions in which OE and TE continue as lessees. OE continues to evaluate the status of its funding obligations for the decommissioning of nuclear facilities.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

CEI is a wholly owned, electric utility subsidiary of FirstEnergy. CEI conducts business in northeastern Ohio, providing regulated electric distribution services. CEI also procures generation services for those customers electing to retain CEI as their power supplier.

For additional information with respect to CEI, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent increased by $84 million in 2010 compared to 2009. The increase in earnings was primarily due to the absence in 2010 of one-time regulatory charges recognized in 2009 and decreased purchased power costs, other operating costs and amortization, partially offset by decreased revenues and deferrals of new regulatory assets.

Revenues

Revenues decreased $455 million, or 27%, in 2010 compared to 2009 due to lower retail generation and distribution revenues.

Distribution revenues decreased $87 million in 2010 compared to 2009 due to lower average unit prices for all customer classes offset by increased KWH deliveries in all sectors. The lower average unit prices were the result of lower transition rates in 2010. Higher residential deliveries resulted from increased weather-related usage in 2010, reflecting a 74% increase in cooling degree days, partially offset by a 5% decrease in heating degree days. Increased industrial deliveries were the result of higher KWH deliveries to major steel customers (101%) and automotive customers (6%), reflecting improved economic conditions.

Changes in distribution KWH deliveries and revenues in the 2010 compared to 2009 are summarized in the following tables:

Distribution KWH Deliveries	Increase
Residential	5.5%
Commercial	2.9%
Industrial	10.9%
Increase in Distribution Deliveries	**7.0%**

Distribution Revenues	Decrease
	(In millions)
Residential	$ (4)
Commercial	(31)
Industrial	(52)
Decrease in Distribution Revenues	**$ (87)**

Retail generation revenues decreased $359 million in 2010 as compared to 2009 primarily due to lower KWH sales to all customer classes. Reduced KWH sales were primarily the result of a 45% increase in customer shopping. Lower KWH sales to residential customers were partially offset by increased KWH deliveries resulting from the previously discussed warmer weather. Decreased volumes were partially offset by higher average unit prices in all customer classes. Retail generation prices increased in 2010 as a result of the CBP auction for the service period beginning June 1, 2009.

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Changes in retail generation sales and revenues in 2010 compared to 2009 are summarized in the following tables:

Retail Generation KWH Sales	**Decrease**
Residential	(50.3)%
Commercial	(67.2)%
Industrial	(44.5)%
Decrease in Retail Generation Sales	**(51.7)%**

Retail Generation Revenues	**Decrease**
	(In millions)
Residential	$ (96)
Commercial	(134)
Industrial	(129)
Decrease in Retail Generation Revenues	**$ (359)**

Expenses

Total expenses decreased $589 million in 2010 compared to 2009. The following table presents changes from the prior period by expense category:

Expenses - Changes	**Increase (Decrease)**
	(In millions)
Purchased power costs	$ (490)
Other operating costs	(31)
Amortization of regulatory assets, net	(201)
Deferral of new regulatory assets	135
General taxes	(2)
Net Decrease in Expenses	**$ (589)**

Purchased power costs decreased in 2010 primarily due to the previously discussed lower KWH sales requirements. Other operating costs decreased due to lower transmission expenses (assumed by third party suppliers beginning June 1, 2009), labor and employee benefit expenses and the absence in 2010 of certain costs incurred in 2009 associated with regulatory obligations for economic development and energy efficiency programs. Decreased amortization of regulatory assets was due primarily to the 2009 impairment of CEI s Extended RTC regulatory asset of $216 million in accordance with the PUCO-approved ESP. A decrease in the deferral of new regulatory assets was primarily due to CEI s contemporaneous recovery of purchased power costs in 2010. General taxes decreased primarily due to a 2010 favorable property tax settlement in Ohio.

Interest Rate Risk

CEI has little exposure to fluctuations in market interest rates because most of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for CEI s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 53	$ 66	$ 75	$ 80	$ 50	$ 16	$ 340	$ 381
Average interest rate	7.7%	7.7%	7.7%	7.7%	7.7%	8%	7.7%	
Liabilities								
Long-term Debt:								
Fixed rate		$ 22	$ 325	$ 26	$ 24	$ 1,456	$ 1,853	$ 2,035
Average interest rate		7.7%	5.8%	7.7%	7.7%	6.8%	6.7%	
Short-term Borrowings:	$ 106						$ 106	$ 106
Average interest rate	1.9%						1.9%	

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THE TOLEDO EDISON COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

TE is a wholly owned electric utility subsidiary of FirstEnergy. TE conducts business in northwestern Ohio, providing regulated electric distribution services. TE also provides generation services to those customers electing to retain TE as their power supplier.

For additional information with respect to TE, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Off-Balance Sheet Arrangements, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent increased by $9 million in 2010 compared to 2009. The increase was primarily due to decreased net amortization of regulatory assets, purchased power and other operating costs, partially offset by an increase in interest expense and decreases in revenues and investment income.

Revenues

Revenues decreased $317 million, or 38%, in 2010 compared to 2009, primarily due to lower retail generation and distribution revenues, partially offset by an increase in wholesale generation revenues.

Distribution revenues decreased $23 million in 2010 compared to 2009, primarily due to lower unit prices, partially offset by higher KWH deliveries to all customer classes. Lower unit prices are primarily due to lower transmission rates. Higher KWH deliveries were influenced by weather-related usage in 2010, reflecting an 85% increase in cooling degree days in TE s service territory, partially offset by a 6% decrease in heating degree days. Increased industrial deliveries were the result of higher KWH deliveries to major automotive customers and steel customers, reflecting improved economic conditions.

Changes in distribution KWH deliveries and revenues in 2010 compared to 2009 are summarized in the following tables:

Distribution KWH Deliveries	Increase
Residential	7.6%
Commercial	3.7%
Industrial	12.3%
Increase in Distribution Deliveries	**8.7%**

Distribution Revenues	Increase (Decrease) *(In millions)*
Residential	$ 1
Commercial	(6)
Industrial	(18)
Net Decrease in Distribution Revenues	**$ (23)**

Retail generation revenues decreased $307 million in 2010 compared to 2009, primarily due to lower KWH sales to all customer classes and lower unit prices to industrial customers. Lower KWH sales to all customer classes were primarily the result of a 48% increase in customer shopping in 2010, partially offset by higher KWH deliveries resulting from the weather conditions described above. Lower unit prices for industrial customers were primarily due to the absence of TE s fuel cost recovery and rate stabilization riders that were effective from January through May 2009, partially offset by increased generation prices resulting from the CBP auction, effective June 1, 2009.

Changes in retail generation KWH sales and revenues in 2010 compared to 2009 are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(39.8)%
Commercial	(69.6)%
Industrial	(55.3)%
Decrease in Retail Generation Sales	**(54.7)%**

Retail Generation Revenues	Decrease
	(In millions)
Residential	$ (60)
Commercial	(112)
Industrial	(135)
Decrease in Retail Generation Revenues	**$ (307)**

Wholesale revenues increased $9 million in 2010 compared to 2009, primarily due to an increase in KWH sales to NGC from TE s leasehold interest in Beaver Valley Unit 2 and higher unit prices.

Expenses

Total expenses decreased $353 million in 2010 compared to 2009. The following table presents changes from the prior period by expense category:

Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$ (285)
Other operating expenses	(34)
Provision for depreciation	1
Amortization (deferral) of regulatory assets, net	(39)
General taxes	4
Net Decrease in Expenses	**$ (353)**

Purchased power costs decreased in 2010 compared to 2009, due to lower volumes required as a result of decreased KWH sales. Other operating costs decreased primarily due to reduced transmission expense (assumed by third party suppliers beginning June 1, 2009) and lower costs associated with regulatory obligations for economic development and energy efficiency programs. The amortization of regulatory assets decreased primarily due to PUCO-approved cost deferrals and lower MISO transmission cost amortization in 2010 compared to 2009. The increase in general taxes was primarily due to higher Ohio KWH taxes in 2010 as compared to 2009 and a $3.5 million Ohio KWH tax adjustment recognized in 2009 related to prior periods.

Other Expense

Other expense increased $17 million in 2010 compared to 2009, primarily due to higher interest expense associated with the April 2009 issuance of $300 million senior secured notes and lower nuclear decommissioning trust investment income.

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Interest Rate Risk

TE has little exposure to fluctuations in market interest rates because most of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for TE s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income		$ 22	$ 25	$ 26	$ 24	$ 48	$ 145	$ 160
Average interest rate		7.7%	7.7%	7.7%	7.7%	5%	6.8%	
Liabilities								
Long-term Debt:								
Fixed rate						$ 600	$ 600	$ 653
Average interest rate						6.7%	6.7%	

Equity Price Risk

Nuclear decommissioning trust funds have been established to satisfy nuclear decommissioning obligations. Included in TE s nuclear decommissioning trust are fixed income and short-term investments carried at a market value of approximately $76 million as of December 31, 2010. TE recognizes in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trust as other-than-temporary impairments. A decline in the value of the nuclear decommissioning trust or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2010, $4 million was contributed to the OE and TE nuclear decommissioning trusts to comply with requirements under certain sale-leaseback transactions in which OE and TE continue as lessees. TE continues to evaluate the status of its funding obligations for the decommissioning of nuclear facilities.

JERSEY CENTRAL POWER & LIGHT COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

JCP&L is a wholly owned, electric utility subsidiary of FirstEnergy. JCP&L conducts business in New Jersey, providing regulated electric transmission and distribution services. JCP&L also procures generation services for franchise customers electing to retain JCP&L as their power supplier. JCP&L procures electric supply to serve its BGS customers through a statewide auction process approved by the NJBPU.

For additional information with respect to JCP&L, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $22 million in 2010 compared to 2009. The increase was primarily due to higher revenues, lower purchased power costs and decreased net amortization of regulatory assets, partially offset by increased other operating costs.

Revenues

Revenues increased by $34 million, or 1%, in 2010 compared with 2009. The increase in revenues was primarily due to higher distribution, wholesale generation and other revenues, partially offset by a decrease in retail generation revenues.

Distribution revenues increased by $62 million in 2010 compared to 2009, due to higher KWH deliveries in all customer classes. Increased usage was due to warmer weather and improved economic conditions in JCP&L s service territory. Decreased composite unit prices in the commercial and industrial classes partially offset the increased volume.

Changes in distribution KWH deliveries and revenues in 2010, compared to 2009, are summarized in the following tables:

Distribution KWH Sales	Increase
Residential	8.5%
Commercial	2.6%
Industrial	1.6%
Increase in Distribution Deliveries	**5.0%**

Distribution Revenues	Increase (Decrease) *(In millions)*
Residential	$ 58
Commercial	5
Industrial	(1)
Net Increase in Distribution Revenues	**$ 62**

In 2010, retail generation revenues decreased by $72 million due to lower KWH sales to the commercial and industrial classes, partially offset by higher KWH sales to the residential class. Lower sales to the commercial and industrial classes were primarily due to an increase in the number of shopping customers. Higher KWH sales to the residential class reflected increased weather-related usage resulting from a 60% increase in cooling degree days in 2010, partially offset by a 5% decrease in heating degree days during the same period.

Changes in retail generation KWH sales and revenues in 2010, compared to 2009, are summarized in the following tables:

Retail Generation KWH Sales	Increase (Decrease)
Residential	6.8%
Commercial	(26.4)%
Industrial	(22.4)%
Net Decrease in Retail Generation Sales	**(6.2)%**

Retail Generation Revenues	Increase (Decrease) *(In millions)*
Residential	$ 85
Commercial	(146)
Industrial	(11)
Net Decrease in Retail Generation Revenues	**$ (72)**

Wholesale generation revenues increased $27 million in 2010 compared to 2009, due primarily to higher wholesale energy prices.

Other revenues increased $17 million in 2010 compared to 2009, primarily due to an increase in transition bond revenues as a result of higher KWH deliveries in all customer classes.

Expenses

Total expenses decreased $29 million in 2010 compared to 2009. The following table presents changes from the prior year by expense category:

Expenses - Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ (46)
Other operating costs	34
Provision for depreciation	4
Amortization of regulatory assets, net	(23)
General taxes	2
Net Decrease in Expenses	**$ (29)**

Purchased power costs decreased in 2010 primarily from reduced requirements due to lower retail generation sales. Other operating costs increased in 2010 primarily due to major storm clean up costs, partially offset by a favorable collective bargaining settlement that reduced expenses by $7 million in the second quarter of 2010. The amortization of regulatory assets decreased in 2010 primarily due to the deferral of storm costs.

Market Risk Information

JCP&L uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

JCP&L is exposed to market risk primarily due to fluctuations in electricity, energy transmission and natural gas prices. To manage the volatility relating to these exposures, JCP&L uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, JCP&L relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. JCP&L uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of December 31, 2010 are summarized by contract year in the following table:

Source of Information- Fair Value by Contract Year	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$	$	$	$	$	$	$
Other external sources[2]	(94)	(47)	(42)	(34)			(217)
Prices based on models					(11)	3	(8)
Total[3]	$ (94)	$ (47)	$ (42)	$ (34)	$ (11)	$ 3	$ (225)

(1) Represents futures and options traded on the New York Mercantile Exchange.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

(3) Includes $225 million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on JCP&L s consolidated financial position or cash flows as of December 31, 2010. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would not have a material effect on JCP&L s net income for the next 12 months.

Interest Rate Risk

JCP&L s exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for JCP&L s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	**2011**	**2012**	**2013**	**2014**	**2015**	**There-after**	**Total**	**Fair Value**
				(In millions)				
Assets								

Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$ 290	$ 290	$ 290
Average interest rate						3.7%	3.7%	
Liabilities								
Long-term Debt:								
Fixed rate	$ 32	$ 34	$ 36	$ 39	$ 41	$ 1,628	$ 1,810	$ 1,962
Average interest rate	5.6%	5.7%	5.7%	5.9%	6%	6.1%	6%	

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Equity Price Risk

Nuclear decommissioning trust funds have been established to satisfy nuclear decommissioning obligations. Included in JCP&L s nuclear decommissioning trust are fixed income, equity securities and short-term investments carried at a market value of approximately $185 million as of December 31, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $10 million reduction in fair value as of December 31, 2010. The decommissioning trust of JCP&L is 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. A decline in the value of the nuclear decommissioning trust or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2010, $3 million was contributed to the JCP&L s nuclear decommissioning trust to comply with regulatory requirements. JCP&L continues to evaluate the status of its funding obligations for the decommissioning of nuclear facilities.

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METROPOLITAN EDISON COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Met-Ed is a wholly owned electric utility subsidiary of FirstEnergy. Met-Ed conducts business in eastern Pennsylvania, providing regulated electric transmission and distribution services. Met-Ed also procures generation service for those customers electing to retain Met-Ed as their power supplier. Met-Ed purchased its POLR and default service requirements from FES through a fixed-price wholesale power sales agreement in 2010. Beginning in 2011, Met-Ed procures power under its Default Service Plan in which full requirements products (energy, capacity, ancillary services, and applicable transmission services) are procured through descending clock auctions.

As authorized by Met-Ed s Board of Directors, Met-Ed repurchased 117,620 shares of the Company s common stock from its parent, FirstEnergy, for $150 million on January 28, 2011.

For additional information with respect to Met-Ed, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Regulatory Matters, Environmental Matters, Other Legal Proceedings and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $2 million, or 4%, in 2010. The increase was primarily due to increased revenues and decreased amortization of net regulatory assets, partially offset by increased purchased power and other operating expenses.

Revenues

Revenue increased $130 million, or 8%, in 2010 compared to 2009, reflecting higher distribution and generation revenues, partially offset by a decrease in transmission revenues.

Distribution revenues increased $86 million in 2010 compared to 2009, primarily due to higher rates resulting from the annual update to Met-Ed s TSC rider effective June 1, 2010, partially offset by lower CTC rates for the residential class. Higher KWH deliveries to industrial customers were due to improved economic conditions in Met-Ed s service territory. Higher residential and commercial KWH deliveries reflect increased weather-related usage due to a 59% increase in cooling degree days in 2010 compared to 2009, partially offset by a 5% decrease in heating degree days for the same period.

Changes in distribution KWH deliveries and revenues in 2010 compared to 2009 are summarized in the following tables:

Distribution KWH Deliveries	**Increase**
Residential	3.8%
Commercial	3.1%
Industrial	4.6%
Increase in Distribution Deliveries	**3.8%**

Distribution Revenues	**Increase**
	(In millions)
Residential	$ 45
Commercial	28
Industrial	13
Increase in Distribution Revenues	**$ 86**

In 2010, retail generation revenues increased $32 million due to higher composite unit prices and higher KWH sales to the residential customer class, partially offset by lower KWH sales to the commercial and industrial customer classes. The higher unit prices were primarily due to an increase in the generation rate effective January 1, 2010. Higher KWH sales to residential customers increased primarily due to weather-related usage described above. Increased customer shopping in the commercial and industrial classes drove the lower KWH sales to those classes.

Changes in retail generation KWH sales and revenues in 2010 compared to 2009 are summarized in the following tables:

Retail Generation KWH Sales	Increase (Decrease)
Residential	3.8%
Commercial	(0.1)%
Industrial	(2.8)%
Net Increase in Retail Generation Sales	**0.8%**

Retail Generation Revenues	Increase (Decrease) *(In millions)*
Residential	$ 36
Commercial	
Industrial	(4)
Net Increase in Retail Generation Revenues	**$ 32**

Wholesale revenues increased $29 million in 2010 compared to 2009, primarily reflecting higher PJM capacity prices. Transmission revenues decreased $19 million in 2010 compared to 2009 primarily due to decreased Financial Transmission Rights revenues. Met-Ed defers the difference between transmission revenues and transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses increased $112 million in 2010 compared to 2009. The following table presents changes from the prior year by expense category:

Expenses - Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ 54
Other operating costs	141
Provision for depreciation	1
Amortization of regulatory assets, net	(84)
Net Increase in Expenses	**$ 112**

Purchased power costs increased $54 million in 2010 compared to 2009 primarily due to an increase in unit costs. Other operating costs increased $141 million in 2010 compared to 2009 primarily due to higher transmission congestion and transmission loss expenses (see reference to deferral accounting above). The amortization of regulatory assets decreased $84 million in 2010 compared to 2009 primarily due to higher expense deferrals resulting from increased PJM transmission costs and reduced amortization due to decreasing regulatory asset balances.

Other Expense

Interest income decreased in 2010 compared to 2009 primarily due to reduced CTC stranded asset balances. That impact was partially offset by lower interest expense due to a $100 million debt repayment in March 2010 and reduced borrowings under the Revolving Credit Facility.

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Market Risk Information

Med-Ed uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

Met-Ed is exposed to market risk primarily due to fluctuations in electricity, energy transmission and natural gas prices. To manage the volatility relating to these exposures, Met-Ed uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, Met-Ed relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Met-Ed uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of December 31, 2010 are summarized by contract year in the following table:

Source of Information- Fair Value by Contract Year	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$	$	$	$	$	$	$
Other external sources[2]	(53)	(48)	(4)	(2)			(107)
Prices based on models					24	83	107
Total	$ (53)	$ (48)	$ (4)	$ (2)	$ 24	$ 83	$

(1) Represents futures and options traded on the New York Mercantile Exchange.

(2) Primarily represents contracts based on broker and Intercontinental Exchange quotes.

Met-Ed performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on Met-Ed s consolidated financial position or cash flows as of December 31, 2010. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would not have a material effect on Met-Ed s net income for the next 12 months.

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Interest Rate Risk

Met-Ed s exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for Met-Ed s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$ 132	$ 132	$ 132
Average interest rate						3.4%	3.4%	
Liabilities								
Long-term Debt:								
Fixed rate			$ 150	$ 250		$ 314	$ 714	$ 793
Average interest rate			5.0%	4.9%		7.6%	6.1%	
Variable rate						$ 29	$ 29	$ 29
Average interest rate						0.3%	0.3%	
Short-term Borrowings:	$ 124						$ 124	$ 124
Average interest rate	0.5%						0.5%	

Equity Price Risk

Nuclear decommissioning trust funds have been established to satisfy nuclear decommissioning obligations. Included in Met-Ed s nuclear decommissioning trust are fixed income, equity securities and short-term investments carried at a market value of approximately $298 million as of December 31, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $16 million reduction in fair value as of December 31, 2010. The decommissioning trust of Med-Ed is 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. A decline in the value of the nuclear decommissioning trust or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2010, $3 million was contributed to the Met-Ed s nuclear decommissioning trust to comply with regulatory requirements. Met-Ed continues to evaluate the status of its funding obligations for the decommissioning of nuclear facilities.

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PENNSYLVANIA ELECTRIC COMPANY
MANAGEMENT S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Penelec is a wholly owned electric utility subsidiary of FirstEnergy. Penelec conducts business in northern and south central Pennsylvania, providing regulated transmission and distribution services. Penelec also procures generation services for those customers electing to retain Penelec as their power supplier. Penelec purchased its POLR and default service requirements from FES through a fixed-price wholesale power sales agreement in 2010. Beginning in 2011, Penelec procures power under its Default Service Plan in which full requirements products (energy, capacity, ancillary services, applicable Transmission Services) are procured through descending clock auctions.

For additional information with respect to Penelec, please see the information contained in FirstEnergy s Management s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Strategy and Outlook, Risks and Challenges, Postretirement Benefits, Supply Plan, Capital Resources and Liquidity, Contractual Obligations, Regulatory Matters, Environmental Matters, Other Legal Proceedings, Critical Accounting Policies and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $6 million in 2010 compared to 2009. The decrease was primarily due to higher purchased power costs, other operating costs and interest expense, partially offset by higher revenues and net deferral of regulatory assets.

Revenues

Revenues increased by $91 million, or 6%, in 2010 compared to 2009. The increase in revenue was primarily due to higher generation revenues, partially offset by lower distribution and transmission revenues.

Distribution revenues increased by $1 million in 2010, compared to 2009, primarily due to an increase in the universal service and energy efficiency rates for the residential customer class and increased KWH sales in all customer classes, partially offset by a decrease in the CTC rate in all customer classes.

Changes in distribution KWH deliveries and revenues in 2010, compared to 2009, are summarized in the following tables:

Distribution KWH Deliveries	Increase
Residential	3.9%
Commercial	3.5%
Industrial	4.8%
Increase in Distribution Deliveries	**4.0%**

Distribution Revenues	Increase (Decrease)
	(In millions)
Residential	$ 28
Commercial	(16)
Industrial	(11)
Net Increase in Distribution Revenues	**$ 1**

Retail generation revenues increased $80 million in 2010, compared to 2009, primarily due to higher unit prices and higher KWH sales in all customer classes. The higher unit prices were primarily due to an increase in the generation rate, effective January 1, 2010. Higher KWH sales to industrial customers were due to improved economic conditions in Penelec s service territory. Higher KWH sales to residential and commercial customers resulted primarily from weather-related usage, reflecting a 94% increase in cooling degree days in 2010, partially offset by a 4% decrease in heating degree days for the same period.

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Changes in retail generation KWH sales and revenues in 2010, compared to 2009, are summarized in the following tables:

Retail Generation KWH Sales	Increase
Residential	3.9%
Commercial	2.7%
Industrial	5.6%
Increase in Retail Generation Sales	**3.9%**

Retail Generation Revenues	Increase
	(In millions)
Residential	$ 22
Commercial	30
Industrial	28
Increase in Retail Generation Revenues	**$ 80**

Wholesale generation revenues increased $33 million in 2010 compared to 2009, due primarily to higher PJM capacity prices.

Transmission revenues decreased by $17 million in 2010 compared to 2009, primarily due to lower Financial Transmission Rights revenue. Penelec defers the difference between transmission revenues and transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses increased $89 million in 2010 compared to 2009. The following table presents changes from the prior year by expense category:

Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$ 121
Other operating costs	60
Amortization (deferral) of regulatory assets, net	(91)
General taxes	(1)
Net Increase in Expenses	**$ 89**

Purchased power costs increased $121 million in 2010 compared to 2009, primarily due to an increase in unit costs and increased volumes purchased to source increased generation sales requirements. Other operating costs increased $60 million in 2010, primarily due to higher transmission congestion and transmission loss expenses (see reference to deferral accounting above). The amortization (deferral) of net regulatory assets decreased $91 million in 2010, primarily due to increased cost deferrals resulting from higher transmission expenses and decreased amortization of regulatory assets resulting from lower CTC revenues. General taxes decreased $1 million primarily due to a favorable ruling on a property tax appeal in the first quarter of 2010.

Other Expense

In 2010, other expense increased $15 million primarily due to an increase in interest expense on long-term debt as a result of a $500 million debt issuance in September 2009.

Market Risk Information

Penelec uses various market risk sensitive instruments, including derivative contracts, to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general oversight to risk management activities.

Commodity Price Risk

Penelec is exposed to market risk primarily due to fluctuations in electricity, energy transmission and natural gas prices. To manage the volatility relating to these exposures, Penelec uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, Penelec relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Penelec uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of December 31, 2010 are summarized by contract year in the following table:

Source of Information- Fair Value by Contract Year	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$	$	$	$	$	$	$
Other external sources[2]	(69)	(68)	(10)	(7)			(154)
Prices based on models					11	33	44
Total[3]	$ (69)	$ (68)	$ (10)	$ (7)	$ 11	$ 33	$ (110)

(1) Represents futures and options traded on the New York Mercantile Exchange.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

(3) Includes $110 million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

Penelec performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on Penelec s consolidated financial position or cash flows as of December 31, 2010. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would not have a material effect on Penelec s net income for the next 12 months.

Interest Rate Risk

Penelec s exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for Penelec s investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						$ 149	$ 149	$ 149
Average interest rate						1.7%	1.7%	
Liabilities								
Long-term Debt:								
Fixed rate				$ 150		$ 950	$ 1,100	$ 1,169
Average interest rate				5.1%		5.8%	5.7%	
Variable rate						$ 20	$ 20	$ 20
Average interest rate						0.3%	0.3%	
Short-term Borrowings:	$ 101						$ 101	$ 101
Average interest rate	0.5%						0.5%	

Equity Price Risk

Nuclear decommissioning trust funds have been established to satisfy nuclear decommissioning obligations. Included in Penelec s nuclear decommissioning trust are fixed income, equity securities and short-term investments carried at a market value of approximately $156 million as of December 31, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in an $8 million reduction in fair value as of December 31, 2010. The decommissioning trust of Penelec s is 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. A decline in the value of the nuclear decommissioning trust or a significant escalation in estimated decommissioning costs could result in additional funding requirements. Penelec continues to evaluate the status of its funding obligations for the decommissioning of nuclear facilities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by ITEM 7A relating to market risk is set forth in ITEM 7. Management Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

The Company s internal auditors, who are responsible to the Audit Committee of the Company s Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010. The effectiveness of the Company s internal control over financial reporting, as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 134.

MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of Ohio Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

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MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of The Cleveland Electric Illuminating Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

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MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of The Toledo Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of Jersey Central Power & Light Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of Metropolitan Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

MANAGEMENT REPORTS

Management s Responsibility for Financial Statements

The consolidated financial statements of Pennsylvania Electric Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company s 2010 consolidated financial statements.

FirstEnergy Corp. s internal auditors, who are responsible to the Audit Committee of FirstEnergy s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy s Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm s independence. The Committee also reviews management s programs to monitor compliance with the Company s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*, management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common stockholders equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio

February 16, 2011

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of Ohio Edison Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of The Cleveland Electric Illuminating Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of The Toledo Edison Company and its subsidiary at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of Jersey Central Power & Light Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of Metropolitan Edison Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, and cash flows present fairly, in all material respects, the financial position of Pennsylvania Electric Company and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	For the Years Ended December 31, 2010	2009	2008
REVENUES:			
Electric utilities	$ 9,815	$ 11,139	$ 12,061
Unregulated businesses	3,524	1,834	1,566
Total revenues*	13,339	12,973	13,627
EXPENSES:			
Fuel	1,432	1,153	1,340
Purchased power	4,624	4,730	4,291
Other operating expenses	2,850	2,697	3,045
Provision for depreciation	746	736	677
Amortization of regulatory assets	722	1,155	1,053
Deferral of regulatory assets		(136)	(316)
General taxes	776	753	778
Impairment of long-lived assets	384	6	
Total expenses	11,534	11,094	10,868
OPERATING INCOME	1,805	1,879	2,759
OTHER INCOME (EXPENSE):			
Investment income	117	204	59
Interest expense	(845)	(978)	(754)
Capitalized interest	165	130	52
Total other expense	(563)	(644)	(643)
INCOME BEFORE INCOME TAXES	1,242	1,235	2,116
INCOME TAXES	482	245	777
NET INCOME	760	990	1,339
Loss attributable to noncontrolling interest	(24)	(16)	(3)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 784	$ 1,006	$ 1,342

BASIC EARNINGS PER SHARE OF COMMON STOCK	$	2.58	$	3.31	$	4.41
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		304		304		304
DILUTED EARNINGS PER SHARE OF COMMON STOCK	$	2.57	$	3.29	$	4.38
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		305		306		307

* Includes $428 million, $395 million and $432 million of excise tax collections in 2010, 2009 and 2008, respectively.

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,019	$ 874
Receivables-		
Customers, net of allowance for uncollectible accounts of $36 in 2010 and $33 in 2009	1,392	1,244
Other, net of allowance for uncollectible accounts of $8 in 2010 and $7 in 2009	176	153
Materials and supplies, at average cost	638	647
Prepaid taxes	199	248
Other	274	154
	3,698	3,320
PROPERTY, PLANT AND EQUIPMENT:		
In service	29,451	27,826
Less Accumulated provision for depreciation	11,180	11,397
	18,271	16,429
Construction work in progress	1,517	2,735
	19,788	19,164
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,973	1,859
Investments in lease obligation bonds	476	543
Other	553	621
	3,002	3,023
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,575	5,575
Regulatory assets	1,826	2,356
Power purchase contract asset	122	200
Other	794	666
	8,317	8,797
	$ 34,805	$ 34,304
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,486	$ 1,834
Short-term borrowings	700	1,081

Accounts payable	872	829
Accrued taxes	326	314
Accrued compensation and benefits	315	293
Derivatives	266	126
Other	733	711
	4,698	5,188
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $0.10 par value, authorized 375,000,000 shares- 304,835,407 shares outstanding	31	31
Other paid-in capital	5,444	5,448
Accumulated other comprehensive loss	(1,539)	(1,415)
Retained earnings	4,609	4,495
Total common stockholders equity	8,545	8,559
Noncontrolling interest	(32)	(2)
Total equity	8,513	8,557
Long-term debt and other long-term obligations	12,579	12,008
	21,092	20,565
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,879	2,468
Retirement benefits	1,868	1,534
Asset retirement obligations	1,407	1,425
Deferred gain on sale and leaseback transaction	959	993
Power purchase contract liability	466	643
Lease market valuation liability	217	262
Other	1,219	1,226
	9,015	8,551
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 7 and 14)		
	$ 34,805	$ 34,304

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

(Dollars in millions)	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		304,835,407	$ 31	$ 5,509	$ (50)	$ 3,487
Earnings available to FirstEnergy Corp.	$ 1,342					1,342
Unrealized loss on derivative hedges, net of $16 million of income tax benefits	(28)				(28)	
Change in unrealized gain on investments, net of $86 million of income tax benefits	(146)				(146)	
Pension and other postretirement benefits, net of $697 million of income tax benefits (Note 3)	(1,156)				(1,156)	
Comprehensive income	$ 12					
Stock options exercised				(36)		
Restricted stock units				(1)		
Stock-based compensation				1		
Cash dividends declared on common stock						(670)
Balance, December 31, 2008		304,835,407	31	5,473	(1,380)	4,159
Earnings available to FirstEnergy Corp.	$ 1,006					1,006
Unrealized gain on derivative hedges, net of $24 million of income taxes	27				27	
Change in unrealized gain on investments, net of $31 million of income tax benefits	(43)				(43)	
Pension and other postretirement benefits, net of $34 million of income taxes (Note 3)	(19)				(19)	
Comprehensive income	$ 971					

Stock options exercised				(3)		
Restricted stock units				7		
Stock-based compensation				1		
Acquisition adjustment of non-controlling interest (Note 8)				(30)		
Cash dividends declared on common stock						(670)
Balance, December 31, 2009		304,835,407	31	5,448	(1,415)	4,495
Earnings available to FirstEnergy Corp.	$ 784					784
Unrealized gain on derivative hedges, net of $14 million of income taxes	22				22	
Unrealized gain on investments, net of $3 million of income taxes	5				5	
Pension and other postretirement benefits, net of $107 million of income tax benefits (Note 3)	(151)				(151)	
Comprehensive income	$ 660					
Stock options exercised				(2)		
Restricted stock units				(3)		
Stock-based compensation				1		
Cash dividends declared on common stock						(670)
Balance, December 31, 2010		304,835,407	$ 31	$ 5,444	$ (1,539)	$ 4,609

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	As of December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 760	$ 990	$ 1,339
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	746	736	677
Amortization of regulatory assets	722	1,155	1,053
Deferral of regulatory assets		(136)	(316)
Nuclear fuel and lease amortization	168	128	112
Deferred purchased power and other costs	(254)	(338)	(226)
Deferred income taxes and investment tax credits, net	470	384	366
Impairment of long-lived assets (Note 19)	384	6	
Investment impairment (Note 2(E))	33	62	123
Deferred rents and lease market valuation liability	(54)	(52)	(95)
Stock based compensation	(1)	20	(64)
Accrued compensation and retirement benefits	89	22	(140)
Gain on asset sales	(2)	(27)	(72)
Electric service prepayment programs		(10)	(77)
Cash collateral, net	(26)	30	(31)
Gain on sales of investment securities held in trusts, net	(55)	(176)	(63)
Loss on debt redemption	5	146	
Interest rate swap transactions	129		
Commodity derivative transactions, net (Note 6)	(81)	229	5
Pension trust contributions		(500)	
Uncertain tax positions	(34)	(210)	(5)
Acquisition of supply requirements		(93)	
Decrease (increase) in operating assets-			
Receivables	(177)	75	(29)
Materials and supplies	2	(11)	(52)
Prepayments and other current assets	100	(19)	(263)
Increase (decrease) in operating liabilities-			
Accounts payable	43	50	10
Accrued taxes	57	(103)	(39)
Accrued interest	7	67	4
Other	45	40	7
Net cash provided from operating activities	$ 3,076	$ 2,465	$ 2,224
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	1,099	4,632	1,367
Short-term borrowings, net			1,494
Redemptions and repayments-			

Long-term debt		(1,015)		(2,610)		(1,034)
Short-term borrowings, net		(378)		(1,246)		
Common stock dividend payments		(670)		(670)		(671)
Other		(19)		(57)		19
Net cash provided from (used for) financing activities	$	(983)	$	49	$	1,175
CASH FLOWS FROM INVESTING ACTIVITIES:						
Property additions		(1,963)		(2,203)		(2,888)
Proceeds from asset sales		117		21		72
Sales of investment securities held in trusts		3,172		2,229		1,656
Purchases of investment securities held in trusts		(3,219)		(2,306)		(1,749)
Customer acquisition costs		(113)				
Cash investments (Note 5)		66		60		60
Other		(8)		14		(134)
Net cash used for investing activities	$	(1,948)	$	(2,185)	$	(2,983)
Net increase in cash and cash equivalents		145		329		416
Cash and cash equivalents at beginning of year		874		545		129
Cash and cash equivalents at end of year	$	1,019	$	874	$	545
SUPPLEMENTAL CASH FLOW INFORMATION:						
Cash paid during the year-						
Interest (net of amounts capitalized)	$	662	$	718	$	667
Income taxes (benefits)	$	(42)	$	173	$	685

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In thousands)	For the Years Ended December 31, 2010	2009	2008
REVENUES:			
Electric sales to affiliates (Note 17)	$ 2,227,277	$ 2,825,959	$ 2,968,323
Electric sales to non-affiliates	3,251,765	1,447,482	1,332,364
Other	348,572	454,896	217,666
Total revenues	5,827,614	4,728,337	4,518,353
EXPENSES:			
Fuel	1,402,839	1,127,463	1,315,293
Purchased power from affiliates (Note 17)	370,692	222,406	101,409
Purchased power from non-affiliates	1,585,207	996,383	778,882
Other operating expenses	1,279,340	1,183,225	1,084,548
Provision for depreciation	243,296	259,393	231,899
General taxes	93,777	86,915	88,004
Impairment of long-lived assets	383,665	6,067	
Total expenses	5,358,816	3,881,852	3,600,035
OPERATING INCOME	468,798	846,485	918,318
OTHER INCOME (EXPENSE):			
Investment income	59,202	125,226	(22,678)
Miscellaneous income	16,667	12,737	1,698
Interest expense affiliates	(9,755)	(10,106)	(29,829)
Interest expense other	(206,100)	(142,120)	(111,682)
Capitalized interest	91,673	60,152	43,764
Total other income (expense)	(48,313)	45,889	(118,727)
INCOME BEFORE INCOME TAXES	420,485	892,374	799,591
INCOME TAXES	151,057	315,290	293,181
NET INCOME	$ 269,428	$ 577,084	$ 506,410

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,281	$ 12
Receivables-		
Customers, net of allowance for uncollectible accounts of $16,591 in 2010 and $12,041 in 2009	365,758	195,107
Associated companies	477,565	318,561
Other, net of allowance for uncollectible accounts of $6,765 in 2010 and $6,702 in 2009	89,550	51,872
Notes receivable from associated companies	396,770	805,103
Materials and supplies, at average cost	545,342	539,541
Derivatives	181,660	31,485
Prepayments and other	60,171	76,297
	2,126,097	2,017,978
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,321,318	10,357,632
Less Accumulated provision for depreciation	4,024,280	4,531,158
	7,297,038	5,826,474
Construction work in progress	1,062,744	2,423,446
	8,359,782	8,249,920
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,145,846	1,088,641
Other	11,704	22,466
	1,157,550	1,111,107
DEFERRED CHARGES AND OTHER ASSETS:		
Accumulated deferred income tax benefits		86,626
Customer intangibles	133,968	16,566
Goodwill	24,248	24,248
Property taxes	41,112	50,125
Unamortized sale and leaseback costs	73,386	72,553
Derivatives	97,603	28,368
Other	48,689	93,297
	419,006	371,783

	$ 12,062,435	$ 11,750,788

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,132,135	$ 1,550,927
Short-term borrowings-		
Associated companies	11,561	9,237
Accounts payable-		
Associated companies	466,623	466,078
Other	241,191	245,363
Accrued taxes	70,129	83,158
Derivatives	266,411	125,609
Other	251,671	233,448
	2,439,721	2,713,820
CAPITALIZATION:		
Total common stockholder s equity	3,788,245	3,514,571
Noncontrolling interest	(504)	
Total equity	3,787,741	3,514,571
Long-term debt and other long-term obligations	3,180,875	2,811,652
	6,968,616	6,326,223
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	959,154	992,869
Accumulated deferred income taxes	57,595	
Accumulated deferred investment tax credits	54,224	58,396
Asset retirement obligations	892,051	921,448
Retirement benefits	285,160	204,035
Property taxes	41,112	50,125
Lease market valuation liability	216,695	262,200
Other	148,107	221,672
	2,654,098	2,710,745
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 7 & 14)		
	$ 12,062,435	$ 11,750,788

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

	As of December 31,	
(Dollars in thousands)	**2010**	**2009**
COMMON STOCKHOLDER S EQUITY:		
Common stock, without par value, authorized 750 shares, 7 shares outstanding	$ 1,490,082	$ 1,468,423
Accumulated other comprehensive loss (Note 2(F))	(120,414)	(103,001)
Retained earnings (Note 11(A))	2,418,577	2,149,149
Total	3,788,245	3,514,571
NONCONTROLLING INTEREST	(504)	
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 11(C)):		
Secured notes:		
FirstEnergy Solutions Corp.		
5.150% due 2010-2015	21,146	21,950
*2.000% due 2011	100,000	100,000
	121,146	121,950
FirstEnergy Generation Corp.		
5.700% due 2014	50,000	50,000
*0.310% due 2017	28,525	28,525
5.630% due 2018	141,260	141,260
*0.290% due 2019	90,140	90,140
5.250% due 2023	50,000	50,000
4.750% due 2029	100,000	100,000
4.750% due 2029	6,450	6,450
*0.300% due 2041	56,600	56,600
	522,975	522,975
FirstEnergy Nuclear Generation Corp.		
8.830% due 2010-2016	3,921	4,514
8.890% due 2010-2016	68,728	77,445
9.000% due 2010-2017	171,924	206,453
9.120% due 2010-2016	53,506	61,455
12.000% due 2010-2017	962	1,072
*0.320% due 2035	60,000	60,000
*0.330% due 2035	98,900	98,900
5.750% due 2033	62,500	62,500
5.875% due 2033	107,500	107,500
	627,941	679,839

Total secured notes	1,272,062	1,324,764
Unsecured notes:		
FirstEnergy Solutions Corp.		
4.800% due 2015	400,000	400,000
6.050% due 2021	600,000	600,000
6.800% due 2039	500,000	500,000
	1,500,000	1,500,000
FirstEnergy Generation Corp.		
7.000% due 2011	4,678	
0.000% due 2016	2,632	
3.000% due 2018	2,805	2,805
3.000% due 2018	2,985	2,985
5.700% due 2020	177,000	177,000
**2.250% due 2023	234,520	234,520
**1.500% due 2028	15,000	15,000
7.125% due 2028	25,000	25,000
**3.375% due 2040	43,000	43,000
*0.320% due 2041	129,610	129,610
**3.000% due 2041	26,000	26,000
3.000% due 2047	46,300	46,300
	709,530	702,220
FirstEnergy Nuclear Generation Corp.		
7.250% due 2032	23,000	23,000
7.250% due 2032	33,000	33,000
**2.250% due 2033	46,500	46,500
**2.750% due 2033	54,600	54,600
**3.750% due 2033	26,000	26,000
**3.375% due 2033	99,100	99,100
**3.375% due 2033	8,000	8,000
*0.280% due 2033	135,550	135,550
*0.330% due 2033	15,500	15,500
3.000% due 2033	20,450	20,450
3.000% due 2033	9,100	9,100
**3.375% due 2034	7,200	7,200
**3.375% due 2034	82,800	82,800
**3.375% due 2035	72,650	72,650
*0.290% due 2035	163,965	163,965
	797,415	797,415
Total unsecured notes	3,006,945	2,999,635
Capital lease obligations (Note 7)	35,788	40,110

Net unamortized discount on debt	(1,785)	(1,930)
Long-term debt due within one year	(1,132,135)	(1,550,927)
Total long-term debt and other long-term obligations	3,180,875	2,811,652
TOTAL CAPITALIZATION	$ 6,968,616	$ 6,326,223

* Denotes variable rate issue with applicable year-end interest rate shown.

** Denotes remarketed unsecured notes in 2010.

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		7	$ 1,164,922	$ 140,654	$ 1,108,655
Net income	$ 506,410				506,410
Net unrealized loss on derivative instruments, net of $5,512 of income tax benefits	(9,200)			(9,200)	
Change in unrealized gain on investments, net of $82,014 of income tax benefits	(137,689)			(137,689)	
Pension and other postretirement benefits, net of $47,853 of income tax benefits (Note 3)	(85,636)			(85,636)	
Comprehensive income	$ 273,885				
Equity contribution from parent			280,000		
Stock options exercised, restricted stock units and other adjustments			13,262		
Consolidated tax benefit allocation			6,045		
Cash dividends declared on common stock					(43,000)
Balance, December 31, 2008		7	1,464,229	(91,871)	1,572,065
Net income	$ 577,084				577,084
Net unrealized gain on derivative instruments, net of $6,766 of income taxes	11,329			11,329	
Change in unrealized gain on investments, net of $20,937 of income tax benefits	(28,306)			(28,306)	
Pension and other postretirement benefits, net of $8,472 of income taxes (Note 3)	5,847			5,847	
Comprehensive income	$ 565,954				
Restricted stock units			866		
Consolidated tax benefit allocation			3,328		
Balance, December 31, 2009		7	1,468,423	(103,001)	2,149,149
Net income	269,428				269,428
	14,363			14,363	

Net unrealized gain on derivative instruments, net of $8,835 of income taxes					
Change in unrealized gain on investments, net of $2,846 of income taxes	4,765			4,765	
Pension and other postretirement benefits, net of $22,369 of income tax benefits (Note 3)	(36,541)			(36,541)	
Comprehensive income	$ 252,015				
Restricted stock units			(329)		
Consolidated tax benefit allocation			21,988		
Balance, December 31, 2010		7	$ 1,490,082	$ (120,414)	$ 2,418,577

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 269,428	$ 577,084	$ 506,410
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	243,296	259,393	231,899
Nuclear fuel and lease amortization	172,132	130,486	111,978
Deferred rents and lease market valuation liability	(47,319)	(46,384)	(43,263)
Deferred income taxes and investment tax credits, net	175,653	219,962	116,626
Impairment of long-lived assets (Note 19)	383,665	6,067	
Investment impairments (Note 2(E))	32,254	57,073	115,207
Accrued compensation and retirement benefits	24,973	6,162	16,011
Commodity derivative transactions, net (Note 6)	(81,362)	228,705	5,100
Gain on asset sales	(2,333)	(10,649)	(38,858)
Gain on investment securities held in trusts, net	(50,693)	(158,112)	(53,290)
Acquisition of supply requirements		(93,371)	
Cash collateral, net	(6,581)	20,208	(60,621)
Associated company lease assignment		71,356	
Decrease (increase) in operating assets-			
Receivables	(361,901)	(34,429)	59,782
Materials and supplies	(11,015)	12,513	(59,983)
Prepayments and other current assets	41,937	(26,046)	(12,302)
Increase (decrease) in operating liabilities-			
Accounts payable	(27,457)	67,855	34,467
Accrued taxes	2,303	6,059	(90,568)
Accrued interest	(1,873)	46,441	1,398
Other	31,015	33,916	12,935
Net cash provided from operating activities	786,122	1,374,289	852,928
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	715,370	2,438,402	618,375
Equity contributions from parent			280,000
Short-term borrowings, net	2,324		700,759
Redemptions and repayments-			
Long-term debt	(772,454)	(709,156)	(462,540)
Short-term borrowings, net		(1,155,586)	
Common stock dividend payments			(43,000)
Other	(2,140)	(21,790)	(5,147)
Net cash provided from (used for) financing activities	(56,900)	551,870	1,088,447

CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(1,034,685)	(1,222,933)	(1,835,629)
Proceeds from asset sales	117,333	18,371	23,077
Sales of investment securities held in trusts	1,926,684	1,379,154	950,688
Purchases of investment securities held in trusts	(1,974,020)	(1,405,996)	(987,304)
Loans from (to) associated companies, net	408,333	(675,928)	(36,391)
Customer acquisition costs	(113,336)		
Leasehold improvement payments to associated companies	(51,204)		
Other	942	(18,854)	(55,779)
Net cash used for investing activities	(719,953)	(1,926,186)	(1,941,338)
Net change in cash and cash equivalents	9,269	(27)	37
Cash and cash equivalents at beginning of period	12	39	2
Cash and cash equivalents at end of period	$ 9,281	$ 12	$ 39
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year-			
Interest (net of amounts capitalized)	$ 116,713	$ 38,446	$ 92,103
Income taxes	$ 139,953	$ 96,045	$ 196,963

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(In thousands)	For the Years Ended December 31, 2010	2009	2008
REVENUES (Note 17):			
Electric sales	$ 1,729,367	$ 2,418,292	$ 2,487,956
Excise and gross receipts tax collections	106,751	98,630	113,805
Total revenues	1,836,118	2,516,922	2,601,761
EXPENSES (Note 17):			
Purchased power from affiliates	521,052	991,405	1,203,314
Purchased power from non-affiliates	316,712	481,406	114,972
Other operating costs	364,274	461,142	565,893
Provision for depreciation	88,154	89,289	79,444
Amortization of regulatory assets, net	62,857	93,694	117,733
General taxes	182,679	171,082	186,396
Total expenses	1,535,728	2,288,018	2,267,752
OPERATING INCOME	300,390	228,904	334,009
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	21,758	46,887	56,103
Miscellaneous income (expense)	4,455	2,654	(4,525)
Interest expense	(88,588)	(90,669)	(75,058)
Capitalized interest	1,197	844	414
Total other expense	(61,178)	(40,284)	(23,066)
INCOME BEFORE INCOME TAXES	239,212	188,620	310,943
INCOME TAXES	81,972	66,186	98,584
NET INCOME	157,240	122,434	212,359
Income from noncontrolling interest	509	567	613
EARNINGS AVAILABLE TO PARENT	$ 156,731	$ 121,867	$ 211,746

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 420,489	$ 324,175
Receivables-		
Customers, net of allowance for uncollectible accounts of $4,086 in 2010 and $5,119 in 2009	176,591	209,384
Associated companies	118,135	98,874
Other	12,232	14,155
Notes receivable from associated companies	16,957	118,651
Prepayments and other	6,393	15,964
	750,797	781,203
UTILITY PLANT:		
In service	3,136,623	3,036,467
Less Accumulated provision for depreciation	1,207,745	1,165,394
	1,928,878	1,871,073
Construction work in progress	45,103	31,171
	1,973,981	1,902,244
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds (Note 7)	190,420	216,600
Nuclear plant decommissioning trusts	127,017	120,812
Other	95,563	96,861
	413,000	434,273
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	400,322	465,331
Pension assets (Note 3)	28,596	19,881
Property taxes	71,331	67,037
Unamortized sale and leaseback costs	30,126	35,127
Other	17,634	39,881
	548,009	627,257
	$ 3,685,787	$ 3,744,977
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,419	$ 2,723

Short-term borrowings-		
Associated companies	142,116	92,863
Other	320	807
Accounts payable-		
Associated companies	99,421	102,763
Other	29,639	40,423
Accrued taxes	78,707	81,868
Accrued interest	25,382	25,749
Other	74,947	81,424
	451,951	428,620
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder s equity	914,411	1,021,110
Noncontrolling interest	5,680	6,442
Total equity	920,091	1,027,552
Long-term debt and other long-term obligations	1,152,134	1,160,208
	2,072,225	2,187,760
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	696,410	660,114
Accumulated deferred investment tax credits	10,159	11,406
Retirement benefits	183,712	174,925
Asset retirement obligations	74,456	85,926
Other	196,874	196,226
	1,161,611	1,128,597
COMMITMENTS AND CONTINGENCIES (Notes 7 and 14)		
	$ 3,685,787	$ 3,744,977

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands)	As of December 31, 2010	2009
COMMON STOCKHOLDER S EQUITY:		
Common stock, without par value, 175,000,000 shares authorized, 60 shares outstanding	$ 951,866	$ 1,154,797
Accumulated other comprehensive loss (Note 2(F))	(179,076)	(163,577)
Retained earnings (Note 11(A))	141,621	29,890
Total	914,411	1,021,110
NONCONTROLLING INTEREST	5,680	6,442
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 11(C)):		
Ohio Edison Company-		
First mortgage bonds:		
8.250% due 2018	25,000	25,000
8.250% due 2038	275,000	275,000
Total	300,000	300,000
Secured notes:		
7.156% weighted average interest rate due 2009-2010		1,257
Total		1,257
Unsecured notes:		
5.450% due 2015	150,000	150,000
6.400% due 2016	250,000	250,000
6.875% due 2036	350,000	350,000
Total	750,000	750,000
Pennsylvania Power Company-		
First mortgage bonds:		
9.740% due 2010-2019	8,799	9,773
6.090% due 2022	100,000	100,000
7.625% due 2023		6,500
Total	108,799	116,273

Secured notes:		
5.400% due 2013		1,000
Total		1,000
Capital lease obligations (Note 7)	6,604	6,884
Net unamortized discount on debt	(11,850)	(12,483)
Long-term debt due within one year	(1,419)	(2,723)
Total long-term debt and other long-term obligations	1,152,134	1,160,208
TOTAL CAPITALIZATION	$ 2,072,225	$ 2,187,760

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		60	$ 1,220,512	$ 48,386	$ 307,277
Earnings available to parent	$ 211,746				211,746
Change in unrealized gain on investments, net of $5,702 of income tax benefits	(10,370)			(10,370)	
Pension and other postretirement benefits, net of $121,425 of income tax benefits (Note 3)	(222,401)			(222,401)	
Comprehensive loss	$ (21,025)				
Restricted stock units			(16)		
Stock-based compensation			1		
Consolidated tax benefit allocation			3,919		
Cash dividends declared on common stock					(265,000)
Balance, December 31, 2008		60	1,224,416	(184,385)	254,023
Earnings available to parent	$ 121,867				121,867
Change in unrealized gain on investments, net of $4,196 of income tax benefits	(5,497)			(5,497)	
Pension and other postretirement benefits, net of $20,257 of income taxes (Note 3)	26,305			26,305	
Comprehensive income available to parent	$ 142,675				
Restricted stock units			81		
Consolidated tax benefit allocation			4,300		
Cash dividends declared on common stock					(346,000)
Cash dividends declared as return of capital			(74,000)		
Balance, December 31, 2009		60	1,154,797	(163,577)	29,890
Earnings available to parent	$ 156,731				156,731
Unrealized gain on investments, net of $246 of income taxes	448			448	
Pension and other postretirement benefits, net of $10,596 of income tax benefits	(15,947)			(15,947)	

(Note 3)					
Comprehensive income available to parent	$ 141,232				
Restricted stock units			117		
Consolidated tax benefit allocation			1,952		
Cash dividends declared on common stock					(45,000)
Cash dividends declared as return of capital			(205,000)		
Balance, December 31, 2010		60	$ 951,866	$ (179,076)	$ 141,621

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 157,240	$ 122,434	$ 212,359
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	88,154	89,289	79,444
Amortization of regulatory assets, net	62,857	93,694	117,733
Amortization of lease costs	(8,609)	(8,211)	(7,702)
Deferred income taxes and investment tax credits, net	46,513	41,178	16,125
Accrued compensation and retirement benefits	(23,025)	(13,729)	17,139
Accrued regulatory obligations	1,047	18,635	
Electric service prepayment programs		(4,634)	(42,215)
Cash collateral from suppliers	2,060	6,469	
Pension trust contributions		(103,035)	
Asset retirement obligation settlements	(10,075)		
Decrease (increase) in operating assets-			
Receivables	26,650	139,679	(61,926)
Prepayments and other current assets	13,639	(10,407)	5,937
Increase (decrease) in operating liabilities-			
Accounts payable	(21,311)	(14,949)	14,166
Accrued taxes	(3,161)	(9,142)	(8,983)
Accrued interest	(367)	76	3,295
Other	(4,712)	8,924	143
Net cash provided from operating activities	326,900	356,271	345,515
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt		100,000	292,169
Short-term borrowings, net	48,766	92,130	
Redemptions and repayments-			
Long-term debt	(10,075)	(101,680)	(249,897)
Short-term borrowings, net			(51,761)
Common stock dividend payments	(250,000)	(420,000)	(315,000)
Other	(1,561)	(2,839)	(4,435)
Net cash used for financing activities	(212,870)	(332,389)	(328,924)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(150,119)	(152,817)	(182,512)
Leasehold improvement payments from associated companies	18,375		
Sales of investment securities held in trusts	83,352	131,478	120,744

Purchases of investment securities held in trusts	(89,406)	(138,925)	(127,680)
Loan repayments from associated companies, net	101,694	102,314	373,138
Collection of principal on long-term notes receivable		195,970	1,756
Cash investments	25,005	20,133	(57,792)
Other	(6,617)	(4,203)	1,366
Net cash provided from (used for) investing activities	(17,716)	153,950	129,020
Net increase in cash and cash equivalents	96,314	177,832	145,611
Cash and cash equivalents at beginning of year	324,175	146,343	732
Cash and cash equivalents at end of year	420,489	$ 324,175	$ 146,343
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year-			
Interest (net of amounts capitalized)	$ 82,895	$ 86,523	$ 67,508
Income taxes	$ 76,152	$ 20,530	$ 118,834

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(In thousands)	**2010**	**2009**	**2008**
REVENUES (Note 17):			
Electric sales	$ 1,152,950	$ 1,609,946	$ 1,746,309
Excise and gross receipts tax collections	68,422	66,192	69,578
Total revenues	1,221,372	1,676,138	1,815,887
EXPENSES (Note 17):			
Purchased power from affiliates	361,317	734,592	766,270
Purchased power from non-affiliates	129,054	245,809	4,210
Other operating costs	130,018	161,407	259,438
Provision for depreciation	72,753	71,908	72,383
Amortization of regulatory assets, net	169,541	370,967	163,534
Deferral of new regulatory assets		(134,587)	(107,571)
General taxes	143,294	145,324	143,058
Total expenses	1,005,977	1,595,420	1,301,322
OPERATING INCOME	215,395	80,718	514,565
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	27,360	31,194	34,392
Miscellaneous income (expense)	2,362	3,911	(495)
Interest expense	(133,351)	(137,171)	(125,976)
Capitalized interest	82	173	786
Total other income (expense)	(103,547)	(101,893)	(91,293)
INCOME (LOSS) BEFORE INCOME TAXES	111,848	(21,175)	423,272
INCOME TAXES	38,673	(10,183)	136,786
NET INCOME (LOSS)	73,175	(10,992)	286,486
Income from noncontrolling interest	1,517	1,714	1,960
EARNINGS AVAILABLE TO PARENT	$ 71,658	$ (12,706)	$ 284,526

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 238	$ 86,230
Receivables-		
Customers, net of allowance for uncollectible accounts of $4,589 in 2010 and $5,239 in 2009	183,744	209,335
Associated companies	77,047	98,954
Other	11,544	11,661
Notes receivable from associated companies	23,236	26,802
Prepayments and other	3,656	9,973
	299,465	442,955
UTILITY PLANT:		
In service	2,396,893	2,310,074
Less Accumulated provision for depreciation	932,246	888,169
	1,464,647	1,421,905
Construction work in progress	38,610	36,907
	1,503,257	1,458,812
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	340,029	388,641
Other	10,074	10,220
	350,103	398,861
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	370,403	545,505
Pension assets (Note 3)		13,380
Property taxes	80,614	77,319
Other	11,486	12,777
	2,151,024	2,337,502
	$ 4,303,849	$ 4,638,130
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 161	$ 117
Short-term borrowings-		
Associated companies	105,996	339,728
Accounts payable-		
Associated companies	32,020	68,634
Other	14,947	17,166
Accrued taxes	84,668	90,511
Accrued interest	18,555	18,466
Other	44,569	45,440
	300,916	580,062
CAPITALIZATION (See Consolidated Statement of Capitalization):		
Common stockholder s equity	1,302,806	1,343,987
Noncontrolling interest	18,017	20,592
Total equity	1,320,823	1,364,579
Long-term debt and other long-term obligations	1,852,530	1,872,750
	3,173,353	3,237,329
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	622,771	644,745
Accumulated deferred investment tax credits	10,994	11,836
Retirement benefits	95,654	69,733
Other	100,161	94,425
	829,580	820,739
COMMITMENTS AND CONTINGENCIES (Note 7 and 14)		
	$ 4,303,849	$ 4,638,130

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands)	As of December 31, 2010	2009
COMMON STOCKHOLDER S EQUITY:		
Common stock, without par value, 105,000,000 shares authorized, 67,930,743 shares outstanding	$ 887,087	$ 884,897
Accumulated other comprehensive loss (Note 2(F))	(153,187)	(138,158)
Retained earnings (Note 11(A))	568,906	597,248
Total	1,302,806	1,343,987
NONCONTROLLING INTEREST	18,017	20,592
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 11(C)):		
First mortgage bonds-		
8.875% due 2018	300,000	300,000
5.500% due 2024	300,000	300,000
Total	600,000	600,000
Secured notes-		
7.880% due 2017	300,000	300,000
Total	300,000	300,000
Unsecured notes-		
5.650% due 2013	300,000	300,000
5.700% due 2017	250,000	250,000
5.950% due 2036	300,000	300,000
7.663% due to associated companies 2010-2016 (Note 8)	102,692	123,008
Total	952,692	973,008
Capital lease obligations (Note 7)	3,044	3,162
Net unamortized discount on debt	(3,045)	(3,303)
Long-term debt due within one year	(161)	(117)
Total long-term debt and other long-term obligations	1,852,530	1,872,750
TOTAL CAPITALIZATION	$ 3,173,353	$ 3,237,329

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		67,930,743	$ 873,536	$ (69,129)	$ 685,428
Earnings available to parent	$ 284,526				284,526
Pension and other postretirement benefits, net of $33,136 of income tax benefits (Note 3)	(65,728)			(65,728)	
Comprehensive income	$ 218,798				
Restricted stock units			(1)		
Stock-based compensation			1		
Consolidated tax benefit allocation			5,249		
Cash dividends declared on common stock					(110,000)
Balance, December 31, 2008		67,930,743	878,785	(134,857)	859,954
Loss applicable to parent	$ (12,706)				(12,706)
Pension and other postretirement benefits, net of $1,923 of income taxes (Note 3)	(3,301)			(3,301)	
Comprehensive loss	$ (16,007)				
Restricted stock units			74		
Consolidated tax benefit allocation			6,038		
Cash dividends declared on common stock					(250,000)
Balance, December 31, 2009		67,930,743	884,897	(138,158)	597,248
Earnings available to parent	$ 71,658				71,658
Pension and other postretirement benefits, net of $11,926 of income tax benefits (Note 3)	(15,029)			(15,029)	
Comprehensive loss	$ 56,629				
Restricted stock units			55		
Consolidated tax benefit allocation			2,135		
Cash dividends declared on common stock					(100,000)
Balance, December 31, 2010		67,930,743	$ 887,087	$ (153,187)	$ 568,906

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 73,175	$ (10,992)	$ 286,486
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Provision for depreciation	72,753	71,908	72,383
Amortization of regulatory assets	169,541	370,967	163,534
Deferral of new regulatory assets		(134,587)	(107,571)
Deferred income taxes and investment tax credits, net	(20,068)	(51,839)	11,918
Accrued compensation and retirement benefits	12,724	8,514	1,563
Accrued regulatory obligations		12,556	
Electric service prepayment programs		(3,510)	(23,634)
Cash collateral from suppliers	889	5,440	
Lease assignment payments to associated company		(40,827)	
Pension trust contributions		(89,789)	
Uncertain tax positions	(2,872)	10,766	(793)
Decrease (increase) in operating assets-			
Receivables	60,762	65,603	66,963
Prepayments and other current assets	6,075	(7,186)	(450)
Increase (decrease) in operating liabilities-			
Accounts payable	(38,833)	(3,479)	13,787
Accrued taxes	(3,700)	2,533	(3,149)
Accrued interest	89	4,534	37
Other	2,090	(3,736)	8,995
Net cash provided from operating activities	332,625	206,876	490,069
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt		298,398	300,000
Short-term borrowings, net		93,577	
Redemptions and repayments-			
Long-term debt	(117)	(151,273)	(213,319)
Short-term borrowings, net	(254,048)		(315,827)
Common stock dividend payments	(100,000)	(275,000)	(185,000)
Other	(4,100)	(6,427)	(6,440)
Net cash used for financing activities	(358,265)	(40,725)	(420,586)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(105,660)	(103,243)	(137,265)
Loan repayments from (loans to) associated companies, net	3,566	(7,741)	33,246

Investment in lessor notes	48,612	37,074	37,707
Other	(6,870)	(6,237)	(3,177)
Net cash used for investing activities	(60,352)	(80,147)	(69,489)
Net increase (decrease) in cash and cash equivalents	(85,992)	86,004	(6)
Cash and cash equivalents at beginning of year	86,230	226	232
Cash and cash equivalents at end of year	$ 238	$ 86,230	$ 226
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year-			
Interest (net of amounts capitalized)	$ 131,546	$ 130,689	$ 122,834
Income taxes	$ 67,651	$ 29,358	$ 153,042

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(In thousands)	For the Years Ended December 31, 2010	2009	2008
REVENUES (Note 17):			
Electric sales	$ 489,310	$ 810,069	$ 865,016
Excise tax collections	27,387	23,839	30,489
Total revenues	516,697	833,908	895,505
EXPENSES (Note 17):			
Purchased power from affiliates	180,523	392,825	410,885
Purchased power from non-affiliates	64,174	136,210	2,459
Other operating costs	108,072	142,203	190,441
Provision for depreciation	31,613	30,727	32,422
Amortization (deferral) of regulatory assets, net	(1,427)	37,820	94,104
General taxes	52,045	47,815	52,324
Total expenses	435,000	787,600	782,635
OPERATING INCOME	81,697	46,308	112,870
OTHER INCOME (EXPENSE) (Note 17):			
Investment income	14,727	24,388	22,823
Miscellaneous expense	(4,206)	(2,436)	(7,820)
Interest expense	(41,883)	(36,512)	(23,286)
Capitalized interest	358	169	164
Total other expense	(31,004)	(14,391)	(8,119)
INCOME BEFORE INCOME TAXES	50,693	31,917	104,751
INCOME TAXES	17,645	7,939	29,824
NET INCOME	33,048	23,978	74,927
Income from noncontrolling interest	4	21	12
EARNINGS AVAILABLE TO PARENT	$ 33,044	$ 23,957	$ 74,915

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE TOLEDO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 149,262	$ 436,712
Receivables-		
Customers	29	75
Associated companies	31,777	90,191
Other, net of allowance for uncollectible accounts of $330 in 2010 and $208 in 2009	18,464	20,180
Notes receivable from associated companies	96,765	85,101
Prepayments and other	2,306	7,111
	298,603	639,370
UTILITY PLANT:		
In service	947,203	912,930
Less Accumulated provision for depreciation	446,401	427,376
	500,802	485,554
Construction work in progress	12,604	9,069
	513,406	494,623
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes (Note 7)	103,872	124,357
Nuclear plant decommissioning trusts	75,558	73,935
Other	1,492	1,580
	180,922	199,872
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	72,059	69,557
Property taxes	24,990	23,658
Other	23,750	55,622
	621,375	649,413
	$ 1,614,306	$ 1,983,278
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 199	$ 222

Accounts payable-		
Associated companies	17,168	78,341
Other	7,351	8,312
Notes payable to associated companies		225,975
Accrued taxes	24,401	25,734
Lease market valuation liability	36,900	36,900
Other	29,076	29,273
	115,095	404,757
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder s equity	393,543	489,878
Noncontrolling interest	2,589	2,696
Total equity	396,132	492,574
Long-term debt and other long-term obligations	600,493	600,443
	996,625	1,093,017
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	132,019	80,508
Accumulated deferred investment tax credits	5,930	6,367
Retirement benefits	71,486	65,988
Asset retirement obligations	28,762	32,290
Lease market valuation liability (Note 7)	199,300	236,200
Other	65,089	64,151
	502,586	485,504
COMMITMENTS AND CONTINGENCIES (Notes 7 and 14)		
	$ 1,614,306	$ 1,983,278

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands)	As of December 31, 2010	2009
COMMON STOCKHOLDER S EQUITY:		
Common stock, $5 par value, 60,000,000 shares authorized, 29,402,054 shares outstanding	$ 147,010	$ 147,010
Other paid-in capital	178,182	178,181
Accumulated other comprehensive loss (Note 2(F))	(49,183)	(49,803)
Retained earnings (Note 11(A))	117,534	214,490
Total	393,543	489,878
NONCONTROLLING INTEREST	2,589	2,696
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 11(C)):		
Secured notes-		
7.250% due 2020	300,000	300,000
6.150% due 2037	300,000	300,000
Total	600,000	600,000
Capital lease obligations (Note 7)	3,270	3,492
Net unamortized discount on debt	(2,578)	(2,827)
Long-term debt due within one year	(199)	(222)
Total long-term debt and other long-term obligations	600,493	600,443
TOTAL CAPITALIZATION	$ 996,625	$ 1,093,017

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		29,402,054	$ 147,010	$ 173,169	$ (10,606)	$ 175,618
Earnings available to parent	$ 74,915					74,915
Unrealized gain on investments, net of $1,421 of income taxes	2,372				2,372	
Pension and other postretirement benefits, net of $11,630 of income tax benefits (Note 3)	(25,138)				(25,138)	
Comprehensive income available to parent	$ 52,149					
Restricted stock units				47		
Stock-based compensation				1		
Consolidated tax benefit allocation				2,662		
Cash dividends declared on common stock						(60,000)
Balance, December 31, 2008		29,402,054	147,010	175,879	(33,372)	190,533
Earnings available to parent	$ 23,957					23,957
Change in unrealized gain on investments, net of $5,756 of income tax benefits	(9,425)				(9,425)	
Pension and other postretirement benefits, net of $874 of income tax benefits (Note 3)	(7,006)				(7,006)	
Comprehensive income available to parent	$ 7,526					
Restricted stock units				71		
Consolidated tax benefit allocation				2,231		
Balance, December 31, 2009		29,402,054	147,010	178,181	(49,803)	214,490
Earnings available to parent	$ 33,044					33,044

Unrealized gain on investments, net of $46 of income taxes	85				85	
Pension and other postretirement benefits, net of $1,190 of income tax benefits (Note 3)	535				535	
Comprehensive income available to parent	$ 33,664					
Restricted stock units				1		
Cash dividends declared on common stock						(130,000)
Balance, December 31, 2010		29,402,054	$ 147,010	$ 178,182	$ (49,183)	$ 117,534

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 33,048	$ 23,978	$ 74,927
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	31,613	30,727	32,422
Amortization (deferral) of regulatory assets, net	(1,427)	37,820	94,104
Deferred rents and lease market valuation liability	(37,839)	(37,839)	(37,938)
Deferred income taxes and investment tax credits, net	28,041	2,003	(16,869)
Accrued compensation and retirement benefits	5,517	3,489	1,483
Accrued regulatory obligations	(36)	4,630	
Electric service prepayment programs		(1,458)	(11,181)
Pension trust contribution		(21,590)	
Cash collateral from suppliers	1,548	2,794	
Lease assignment payment to associated company		(30,529)	
Gain on sales of investment securities held in trusts	(2,348)	(7,130)	(626)
Uncertain tax positions	(1,831)	3,038	(1,219)
Decrease (increase) in operating assets-			
Receivables	82,369	(18,872)	20,186
Prepayments and other current assets	6,464	(5,898)	(348)
Increase (decrease) in operating liabilities-			
Accounts payable	(60,183)	35,192	(164,397)
Accrued taxes	(1,333)	(1,932)	(5,812)
Accrued interest		3,625	(17)
Other	(7,653)	(1,120)	(1,456)
Net cash provided from (used for) operating activities	75,950	20,928	(16,741)
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt		297,422	
Short-term borrowings, net		114,733	97,846
Redemptions and repayments-			
Long-term debt	(222)	(347)	(3,860)
Short-term borrowings, net	(225,975)		
Common stock dividend payments	(130,000)	(25,000)	(70,000)
Other	(112)	(351)	(131)
Net cash provided from (used for) financing activities	(356,309)	386,457	23,855
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(42,097)	(47,028)	(57,385)

Leasehold improvement payments from associated companies	32,829		
Loan repayments from (loans to) associated companies, net	(11,664)	63,711	43,098
Redemption of lessor notes (Note 7)	20,485	18,330	11,959
Sales of investment securities held in trusts	125,557	168,580	37,931
Purchases of investment securities held in trusts	(127,323)	(170,996)	(40,960)
Other	(4,878)	(3,284)	(1,765)
Net cash provided from (used for) investing activities	(7,091)	29,313	(7,122)
Net increase (decrease) in cash and cash equivalents	(287,450)	436,698	(8)
Cash and cash equivalents at beginning of year	436,712	14	22
Cash and cash equivalents at end of year	149,262	$ 436,712	$ 14
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$ 41,162	$ 32,353	$ 22,203
Income taxes	$ (13,456)	$ 1,350	$ 62,879

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(In thousands)	For the Years Ended December 31, 2010	2009	2008
REVENUES:			
Electric sales	$ 2,976,452	$ 2,943,590	$ 3,420,772
Excise tax collections	50,636	49,097	51,481
Total revenues	3,027,088	2,992,687	3,472,253
EXPENSES:			
Purchased power	1,736,318	1,782,435	2,206,251
Other operating costs	344,135	309,791	302,894
Provision for depreciation	107,167	102,912	96,482
Amortization of regulatory assets	320,561	344,158	364,816
General taxes	65,396	63,078	67,340
Total expenses	2,573,577	2,602,374	3,037,783
OPERATING INCOME	453,511	390,313	434,470
OTHER INCOME (EXPENSE):			
Miscellaneous income (expense)	6,303	5,272	(1,037)
Interest expense (Note 17)	(120,152)	(116,851)	(99,459)
Capitalized interest	697	543	1,245
Total other expense	(113,152)	(111,036)	(99,251)
INCOME BEFORE INCOME TAXES	340,359	279,277	335,219
INCOME TAXES	148,264	108,778	148,231
NET INCOME	$ 192,095	$ 170,499	$ 186,988

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS

(Dollars In thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4	$ 27
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,769 in 2010 and $3,506 in 2009	323,044	300,991
Associated companies	53,780	12,884
Other	26,119	21,877
Notes receivable associated companies	177,228	102,932
Prepaid taxes	10,889	34,930
Other	12,654	12,945
	603,718	486,586
UTILITY PLANT:		
In service	4,562,781	4,463,490
Less Accumulated provision for depreciation	1,656,939	1,617,639
	2,905,842	2,845,851
Construction work in progress	63,535	54,251
	2,969,377	2,900,102
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	207,561	199,677
Nuclear plant decommissioning trusts	181,851	166,768
Other	2,104	2,149
	391,516	368,594
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,810,936	1,810,936
Regulatory assets	513,395	888,143
Other	27,938	27,096
	2,352,269	2,726,175
	$ 6,316,880	$ 6,481,457
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 32,402	$ 30,667
Accounts payable-		
Associated companies	28,571	26,882
Other	158,442	168,093
Accrued compensation and benefits	35,232	32,814
Customer deposits	23,385	23,636
Accrued interest	18,111	18,256
Other	24,772	67,272
	320,915	367,620
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder s equity	2,618,786	2,600,396
Long-term debt and other long-term obligations	1,769,849	1,801,589
	4,388,635	4,401,985
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	715,527	687,545
Power purchase contract liability	233,492	399,105
Nuclear fuel disposal costs	196,768	196,511
Retirement benefits	182,364	150,603
Asset retirement obligations	108,297	101,568
Other	170,882	176,520
	1,607,330	1,711,852
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 7 and 14)		
	$ 6,316,880	$ 6,481,457

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands)	As of December 31, 2010	2009
COMMON STOCKHOLDER S EQUITY:		
Common stock, $10 par value, 16,000,000 shares authorized, 13,628,447 shares outstanding	$ 136,284	$ 136,284
Other paid-in capital	2,508,874	2,507,049
Accumulated other comprehensive loss (Note 2(F))	(253,542)	(243,012)
Retained earnings (Note 11(A))	227,170	200,075
Total	2,618,786	2,600,396
LONG-TERM DEBT (Note 11(C)):		
Secured notes-		
5.390% due 2008-2010		13,629
5.250% due 2008-2012	14,268	23,974
5.810% due 2010-2013	69,772	77,075
5.410% due 2012-2014	25,693	25,693
6.160% due 2013-2017	99,517	99,517
5.520% due 2014-2018	49,220	49,220
5.610% due 2018-2021	51,139	51,139
Total	309,609	340,247
Unsecured notes-		
5.625% due 2016	300,000	300,000
5.650% due 2017	250,000	250,000
4.800% due 2018	150,000	150,000
7.350% due 2019	300,000	300,000
6.400% due 2036	200,000	200,000
6.150% due 2037	300,000	300,000
Total	1,500,000	1,500,000
Capital lease obligations (Note 7)	108	136
Unamortized discount on debt	(7,466)	(8,127)
Long-term debt due within one year	(32,402)	(30,667)
Total long-term debt	1,769,849	1,801,589
TOTAL CAPITALIZATION	$ 4,388,635	$ 4,401,985

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		14,421,637	$ 144,216	$ 2,655,941	$ (19,881)	$ 237,588
Net income	$ 186,988					186,988
Net unrealized gain on derivative instruments	276				276	
Pension and other postretirement benefits, net of $131,317 of income tax benefits (Note 3)	(196,933)				(196,933)	
Comprehensive loss	$ (9,669)					
Restricted stock units				3		
Stock-based compensation				1		
Consolidated tax benefit allocation				4,065		
Cash dividends declared on common stock						(268,000)
Purchase accounting fair value adjustment				(15,254)		
Balance, December 31, 2008		14,421,637	144,216	2,644,756	(216,538)	156,576
Net income	$ 170,499					170,499
Net unrealized gain on derivative instruments, net of $11 of income tax benefits	288				288	
Pension and other postretirement benefits, net of $13,025 of income tax benefits (Note 3)	(26,762)				(26,762)	
Comprehensive income	$ 144,025					
Restricted stock units				99		
Cash dividends declared on common stock						(127,000)
Repurchase of common stock		(793,190)	(7,932)	(137,806)		

Balance, December 31, 2009		13,628,447	136,284	2,507,049	(243,012)	200,075
Net income	$ 192,095					192,095
Net unrealized loss on derivative instruments, net of $463 of income taxes	(187)				(187)	
Pension and other postretirement benefits, net of $9,065 of income tax benefits (Note 3)	(10,343)				(10,343)	
Comprehensive income	$ 181,565					
Restricted stock units				59		
Cash dividends declared on common stock						(165,000)
Consolidated tax benefit allocation				1,766		
Balance, December 31, 2010		13,628,447	$ 136,284	$ 2,508,874	$ (253,542)	$ 227,170

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 192,095	$ 170,499	$ 186,988
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	107,167	102,912	96,482
Amortization of regulatory assets	320,561	344,158	364,816
Deferred purchased power and other costs	(104,842)	(148,308)	(165,071)
Deferred income taxes and investment tax credits, net	31,645	42,800	12,834
Accrued compensation and retirement benefits	14,055	12,915	(35,791)
Cash collateral from (returned to) suppliers	(22,341)	(210)	23,106
Pension trust contributions		(100,000)	
Decrease (increase) in operating assets-			
Receivables	(67,191)	42,532	8,042
Prepayments and other current assets	23,595	(24,333)	(9,252)
Increase (decrease) in operating liabilities-			
Accounts payable	(19,465)	(24,677)	10,174
Accrued taxes	11,739	(14,265)	2,582
Accrued interest	(145)	9,059	(121)
Other	(9,966)	(11,246)	(13,002)
Net cash provided from operating activities	476,907	401,836	481,787
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt		299,619	
Redemptions and repayments-			
Long-term debt	(30,639)	(29,094)	(27,206)
Short-term borrowings, net		(121,380)	(9,001)
Common stock		(150,000)	
Common stock dividend payments	(165,000)	(127,000)	(268,000)
Other	(2)	(2,281)	(80)
Net cash used for financing activities	(195,641)	(130,136)	(304,287)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(182,368)	(166,409)	(178,358)
Proceeds from asset sales			20,000
Loan repayments from (loans to) associated companies, net	(74,296)	(86,678)	2,173
Sales of investment securities held in trusts	411,470	397,333	248,185
Purchases of investment securities held in trusts	(428,214)	(413,693)	(265,441)
Restricted funds	(1,322)	5,015	(689)

Other	(6,559)	(7,307)	(3,398)
Net cash used for investing activities	(281,289)	(271,739)	(177,528)
Net decrease in cash and cash equivalents	(23)	(39)	(28)
Cash and cash equivalents at beginning of year	27	66	94
Cash and cash equivalents at end of year	$ 4	$ 27	$ 66
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year-			
Interest (net of amounts capitalized)	$ 117,454	$ 108,650	$ 99,731
Income taxes	$ 144,939	$ 95,764	$ 145,943

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(In thousands)	For the Years Ended December 31, 2010	2009	2008
REVENUES:			
Electric sales	$ 1,733,651	$ 1,611,088	$ 1,573,781
Excise tax collections	84,896	77,894	79,221
Total revenues	1,818,547	1,688,982	1,653,002
EXPENSES (Note 17):			
Purchased power from affiliates	612,496	365,491	303,779
Purchased power from non-affiliates	342,988	536,054	593,203
Other operating costs	418,569	277,024	429,745
Provision for depreciation	52,176	51,006	44,556
Amortization of regulatory assets, net	160,360	244,709	21,504
General taxes	87,829	87,799	85,643
Total expenses	1,674,418	1,562,083	1,478,430
OPERATING INCOME	144,129	126,899	174,572
OTHER INCOME (EXPENSE):			
Interest income	3,019	9,709	17,647
Miscellaneous income	5,901	4,033	105
Interest expense (Note 17)	(52,829)	(56,683)	(43,651)
Capitalized interest	653	159	258
Total other expense	(43,256)	(42,782)	(25,641)
INCOME BEFORE INCOME TAXES	100,873	84,117	148,931
INCOME TAXES	42,866	28,594	60,898
NET INCOME	$ 58,007	$ 55,523	$ 88,033

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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METROPOLITAN EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 243,220	$ 120
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,868 in 2010 and $4,044 in 2009	178,522	171,052
Associated companies	24,920	29,413
Other	13,007	11,650
Notes receivable from associated companies	11,028	97,150
Prepaid taxes	343	15,229
Other	2,289	1,459
	473,329	326,073
UTILITY PLANT:		
In service	2,247,853	2,162,815
Less Accumulated provision for depreciation	846,003	810,746
	1,401,850	1,352,069
Construction work in progress	23,663	14,901
	1,425,513	1,366,970
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	289,328	266,479
Other	884	890
	290,212	267,369
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	295,856	356,754
Power purchase contract asset	111,562	176,111
Other	31,699	36,544
	855,616	985,908
	$ 3,044,670	$ 2,946,320
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 28,760	$ 128,500
Short-term borrowings-		
Associated companies	124,079	
Accounts payable-		
Associated companies	33,942	40,521
Other	29,862	41,050
Accrued taxes	60,856	11,170
Accrued interest	16,114	17,362
Other	29,278	24,520
	322,891	263,123
CAPITALIZATION (See Consolidated Statement of Capitalization):		
Common stockholder s equity	1,087,099	1,057,918
Long-term debt and other long-term obligations	718,860	713,873
	1,805,959	1,771,791
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	473,009	453,462
Accumulated deferred investment tax credits	6,866	7,313
Nuclear fuel disposal costs	44,449	44,391
Asset retirement obligations	192,659	180,297
Retirement benefits	29,121	33,605
Power purchase contract liability	116,027	143,135
Other	53,689	49,203
	915,820	911,406
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 7 and 14)		
	$ 3,044,670	$ 2,946,320

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands)	As of December 31, 2010	2009
COMMON STOCKHOLDER S EQUITY:		
Common stock, without par value, 900,000 shares authorized, 859,500 shares outstanding	$ 1,197,076	$ 1,197,070
Accumulated other comprehensive loss (Note 2(F))	(142,383)	(143,551)
Retained earnings (Note 11(A))	32,406	4,399
Total	1,087,099	1,057,918
LONG-TERM DEBT (Note 11(C)):		
First mortgage bonds-		
5.950% due 2027	13,690	13,690
Total	13,690	13,690
Unsecured notes-		
4.450% due 2010		100,000
4.950% due 2013	150,000	150,000
4.875% due 2014	250,000	250,000
7.700% due 2019	300,000	300,000
* 0.330% due 2021	28,500	28,500
Total	728,500	828,500
Capital lease obligations (Note 7)	5,158	
Unamortized premium on debt	272	183
Long-term debt due within one year	(28,760)	(128,500)
Total long-term debt	718,860	713,873
TOTAL CAPITALIZATION	$ 1,805,959	$ 1,771,791

* Denotes variable rate issue with applicable year-end interest rate shown.

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income (Loss)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)
Balance, January 1, 2008		859,500	$ 1,203,186	$ (15,397)	$ (139,157)
Net income	$ 88,033				88,033
Net unrealized gain on derivative instruments	335			335	
Pension and other postretirement benefits, net of $86,030 of income tax benefits (Note 3)	(125,922)			(125,922)	
Comprehensive loss	$ (37,554)				
Restricted stock units			9		
Stock-based compensation			1		
Consolidated tax benefit allocation			791		
Purchase accounting fair value adjustment			(7,815)		
Balance, December 31, 2008		859,500	1,196,172	(140,984)	(51,124)
Net income	$ 55,523				55,523
Net unrealized gain on derivative instruments	335			335	
Pension and other postretirement benefits, net of $2,784 of income taxes (Note 3)	(2,902)			(2,902)	
Comprehensive income	$ 52,956				
Restricted stock units			55		
Consolidated tax benefit allocation			843		
Balance, December 31, 2009		859,500	1,197,070	(143,551)	4,399
Net income	$ 58,007				58,007
Net unrealized loss on derivative instruments, net of $522 of income taxes	(187)			(187)	
Pension and other postretirement benefits, net of	1,355			1,355	

$1,066 of income tax benefits (Note 3)					
Comprehensive income	$ 59,175				
Restricted stock units			6		
Cash dividends declared on common stock					(30,000)
Balance, December 31, 2010		859,500	$ 1,197,076	$ (142,383)	$ 32,406

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 58,007	$ 55,523	$ 88,033
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	52,176	51,006	44,556
Amortization of regulatory assets, net	160,360	244,709	21,504
Deferred costs recoverable as regulatory assets	(62,462)	(96,304)	(25,132)
Deferred income taxes and investment tax credits, net	29,528	66,965	49,939
Accrued compensation and retirement benefits	(2,474)	5,876	(23,244)
Cash collateral from (to) suppliers	2,141	(4,580)	
Pension trust contribution		(123,521)	
Decrease (increase) in operating assets-			
Receivables	(424)	(32,088)	(24,282)
Prepayments and other current assets	14,057	(8,948)	8,223
Increase (decrease) in operating liabilities-			
Accounts payable	(18,598)	(2,781)	(12,512)
Accrued taxes	39,375	(5,001)	470
Accrued interest	(1,248)	10,607	(23)
Other	8,026	5,022	15,629
Net cash provided from operating activities	278,464	166,485	143,161
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt		300,000	28,500
Short-term borrowings, net	124,079		
Redemptions and repayments-			
Long-term debt	(100,000)		(28,568)
Short-term borrowings, net		(265,003)	(20,324)
Common stock dividend payments	(30,000)		
Other		(2,268)	(266)
Net cash provided from (used for) financing activities	(5,921)	32,729	(20,658)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(107,230)	(100,201)	(110,301)
Sales of investment securities held in trusts	460,277	67,973	181,007
Purchases of investment securities held in trusts	(470,192)	(77,738)	(193,061)
Loans from (to) associated companies, net	86,122	(85,704)	1,128
Other, net	1,580	(3,568)	(1,267)

Net cash used for investing activities	(29,443)	(199,238)	(122,494)
Net increase (decrease) in cash and cash equivalents	243,100	(24)	9
Cash and cash equivalents at beginning of year	120	144	135
Cash and cash equivalents at end of year	$ 243,220	$ 120	$ 144
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$ 49,285	$ 41,809	$ 38,627
Income taxes	$ (43,227)	$ (5,801)	$ 16,872

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(In thousands)	For the Years Ended December 31, 2010	2009	2008
REVENUES:			
Electric sales	$ 1,471,956	$ 1,385,574	$ 1,443,461
Gross receipts tax collections	67,915	63,372	70,168
Total revenues	1,539,871	1,448,946	1,513,629
EXPENSES (Note 17):			
Purchased power from affiliates	643,152	341,645	284,074
Purchased power from non-affiliates	364,647	544,490	591,487
Other operating costs	268,614	209,156	228,257
Provision for depreciation	61,141	61,317	54,643
Amortization (deferral) of regulatory assets, net	(34,819)	56,572	71,091
General taxes	73,285	73,839	79,604
Total expenses	1,376,020	1,287,019	1,309,156
OPERATING INCOME	163,851	161,927	204,473
OTHER INCOME (EXPENSE):			
Miscellaneous income	5,928	3,662	1,359
Interest expense (Note 17)	(69,864)	(54,605)	(59,424)
Capitalized interest	750	98	(591)
Total other expense	(63,186)	(50,845)	(58,656)
INCOME BEFORE INCOME TAXES	100,665	111,082	145,817
INCOME TAXES	41,173	45,694	57,647
NET INCOME	$ 59,492	$ 65,388	$ 88,170

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5	$ 14
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,369 in 2010 and $3,483 in 2009	148,864	139,302
Associated companies	54,052	77,338
Other	11,314	18,320
Notes receivable from associated companies	14,404	14,589
Prepaid taxes	14,026	18,946
Other	1,592	1,400
	244,257	269,909
UTILITY PLANT:		
In service	2,532,629	2,431,737
Less Accumulated provision for depreciation	935,259	901,990
	1,597,370	1,529,747
Construction work in progress	30,505	24,205
	1,627,875	1,553,952
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	152,928	142,603
Non-utility generation trusts	80,244	120,070
Other	297	289
	233,469	262,962
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	768,628
Regulatory assets	163,407	9,045
Power purchase contract asset	5,746	15,362
Other	19,287	19,143
	957,068	812,178
	$ 3,062,669	$ 2,899,001

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:

Currently payable long-term debt	$ 45,000	$ 69,310
Short-term borrowings-		
Associated companies	101,338	41,473
Accounts payable-		
Associated companies	35,626	39,884
Other	41,420	41,990
Accrued taxes	5,075	6,409
Accrued interest	17,378	17,598
Other	22,541	22,741
	268,378	239,405
CAPITALIZATION (See Consolidated Statement of Capitalization):		
Common stockholder s equity	899,538	931,386
Long-term debt and other long-term obligations	1,072,262	1,072,181
	1,971,800	2,003,567
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	371,877	242,040
Retirement benefits	187,621	174,306
Asset retirement obligations	98,132	91,841
Power purchase contract liability	116,972	100,849
Other	47,889	46,993
	822,491	656,029
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 7 and 14)		
	$ 3,062,669	$ 2,899,001

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands)	**As of December 31, 2010**	**2009**
COMMON STOCKHOLDER S EQUITY:		
Common stock, $20 par value, 5,400,000 shares authorized, 4,427,577 shares outstanding	$ 88,552	$ 88,552
Other paid-in capital	913,519	913,437
Accumulated other comprehensive income (loss) (Note 2(F))	(163,526)	(162,104)
Retained earnings (Note 11(A))	60,993	91,501
Total	899,538	931,386
LONG-TERM DEBT (Note 11(C)):		
First mortgage bonds-		
5.350% due 2010		12,310
5.350% due 2010		12,000
Total		24,310
Unsecured notes-		
5.125% due 2014	150,000	150,000
6.050% due 2017	300,000	300,000
6.625% due 2019	125,000	125,000
*0.330% due 2020	20,000	20,000
5.200% due 2020	250,000	250,000
*0.340% due 2025		25,000
2.250% due 2025	25,000	
6.150% due 2038	250,000	250,000
Total	1,120,000	1,120,000
Net unamortized discount on debt	(2,738)	(2,819)
Long-term debt due within one year	(45,000)	(69,310)
Total long-term debt	1,072,262	1,072,181
TOTAL CAPITALIZATION	$ 1,971,800	$ 2,003,567

* Denotes variable rate issue with applicable year-end interest rate shown.

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

(Dollars in thousands)	Comprehensive Income (Loss)	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		4,427,577	$ 88,552	$ 920,616	$ 4,946	$ 57,943
Net income	$ 88,170					88,170
Net unrealized gain on investments, net of $13 of income taxes	9				9	
Net unrealized gain on derivative instruments, net of $4 of income tax benefits	69				69	
Pension and other postretirement benefits, net of $90,822 of income tax benefits (Note 3)	(133,021)				(133,021)	
Comprehensive loss	$ (44,773)					
Restricted stock units				35		
Stock-based compensation				1		
Consolidated tax benefit allocation				1,066		
Cash dividends declared on common stock						(70,000)
Purchase accounting fair value adjustment				(9,277)		
Balance, December 31, 2008		4,427,577	88,552	912,441	(127,997)	76,113
Net income	$ 65,388					65,388
Change in unrealized gain on investments, net of $15 of income taxes	(2)				(2)	
Net unrealized gain on derivative instruments, net of $7 of income tax benefits	72				72	
Pension and other postretirement benefits, net of $17,244 of income tax benefits (Note 3)	(34,177)				(34,177)	
Comprehensive income	$ 31,281					
Restricted stock units				65		
Consolidated tax benefit allocation				931		
Cash dividends declared on common stock						(50,000)

Balance, December 31, 2009		4,427,577	88,552	913,437	(162,104)	91,501
Net income	$ 59,492					59,492
Net unrealized loss on derivative instruments, net of $105 of income taxes	(40)				(40)	
Pension and other postretirement benefits, net of $4,367 of income tax benefits (Note 3)	(1,382)				(1,382)	
Comprehensive income	$ 58,070					
Restricted stock units				82		
Cash dividends declared on common stock						(90,000)
Balance, December 31, 2010		4,427,577	$ 88,552	$ 913,519	$ (163,526)	$ 60,993

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)	For the Years Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 59,492	$ 65,388	$ 88,170
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	61,141	61,317	54,643
Amortization (deferral) of regulatory assets, net	(34,819)	56,572	71,091
Deferred costs recoverable as regulatory assets	(89,070)	(100,990)	(35,898)
Deferred income taxes and investment tax credits, net	133,885	63,065	95,227
Accrued compensation and retirement benefits	8,206	3,866	(25,661)
Cash collateral paid, net	(3,980)		
Pension trust contribution		(60,000)	
Decrease (increase) in operating assets-			
Receivables	24,687	22,891	(74,338)
Prepayments and other current assets	4,728	(2,519)	(16,313)
Increase (decrease) in operating liabilities-			
Accounts payable	(5,128)	3,114	(1,966)
Accrued taxes	(10,089)	(6,855)	(2,181)
Accrued interest	(220)	4,467	(36)
Other	4,909	3,236	17,815
Net cash provided from operating activities	153,742	113,552	170,553
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	25,000	498,583	45,000
Short-term borrowings, net	59,865		66,509
Redemptions and repayments-			
Long-term debt	(49,310)	(135,000)	(45,556)
Short-term borrowings, net		(239,929)	
Common stock dividend payments	(90,000)	(85,000)	(90,000)
Other	(48)	(4,453)	
Net cash provided from (used for) financing activities	(54,493)	34,201	(24,047)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(126,344)	(124,262)	(126,672)
Loan repayments from associated companies, net	185	244	1,480
Sales of investment securities held in trusts	164,627	84,400	117,751
Purchases of investment securities held in trusts	(129,714)	(98,467)	(134,621)
Other, net	(8,012)	(9,677)	(4,467)

Net cash used for investing activities	(99,258)	(147,762)	(146,529)
Net decrease in cash and cash equivalents	(9)	(9)	(23)
Cash and cash equivalents at beginning of year	14	23	46
Cash and cash equivalents at end of year	$ 5	$ 14	$ 23
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year-			
Interest (net of amounts capitalized)	$ 67,208	$ 48,265	$ 56,972
Income taxes	$ (115,870)	$ (10,775)	$ 44,197

The accompanying Combined Notes to the Consolidated Financial Statements are an integral part of these financial statements.

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COMBINED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, FENOC, FES and its subsidiaries FGCO and NGC and FESC.

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

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation unless otherwise prescribed by GAAP (see Note 15). FirstEnergy consolidates a VIE (see Note 8) when it is determined to be the VIE s primary beneficiary. Investments in non-consolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control (20-50% owned companies, joint ventures and partnerships) are accounted for under the equity method. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity s earnings is reported in the Consolidated Statements of Income. These footnotes combine results of FE, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec.

Certain prior year amounts have been reclassified to conform to the current year presentation. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of 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.

Regulatory assets on the Balance Sheets are comprised of the following:

Regulatory Assets	**FE**	**OE**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)			
December 31, 2010							
Regulatory transition costs	$ 770	$	$	$	$ 591	$ 131	$ 43
Customer shopping incentives							
Customer receivables for future income taxes	326	50	2	1	30	113	130
Loss (gain) on reacquired debt	48	17	1	(3)	21	6	6
Employee postretirement benefits	16		3	2	7	4	
Nuclear decommissioning, decontamination and spent fuel disposal costs	(184)				(31)	(92)	(61)
Asset removal costs	(237)	(24)	(47)	(19)	(147)		
MISO/PJM transmission costs	184	(1)				131	52
Deferred generation costs	386	125	226	35			
Distribution costs	426	216	155	55			
Other	91	17	30	1	42	3	(7)
Total	$ 1,826	$ 400	$ 370	$ 72	$ 513	$ 296	$ 163
December 31, 2009							
Regulatory transition costs	$ 1,100	$ 73	$ 8	$ 8	$ 965	$ 116	$ (70)
Customer shopping incentives	154		154				
Customer receivables for future income taxes	329	58	3	1	31	114	122
Loss (gain) on reacquired debt	51	18	1	(3)	22	8	5
Employee postretirement benefits	23		5	2	10	6	
Nuclear decommissioning, decontamination and spent fuel disposal costs	(162)				(22)	(83)	(57)
Asset removal costs	(231)	(23)	(43)	(17)	(148)		
MISO/PJM transmission costs	148	(15)	(15)	(3)		187	(6)
Deferred generation costs	369	115	222	32			
Distribution costs	482	230	197	55			
Other	93	9	14	(5)	30	9	15
Total	$ 2,356	$ 465	$ 546	$ 70	$ 888	$ 357	$ 9

Regulatory assets that do not earn a current return totaled approximately $215 million as of December 31, 2010 (JCP&L $38 million, Met-Ed $131 million, Penelec $12 million, OE $18 million and, CEI $16 million). Regulatory assets of JCP&L, Met-Ed and Penelec not earning a current return are primarily for certain regulatory transition costs and employee postretirement benefits and will be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec. Regulatory assets of OE and CEI not earning a current return primarily relate to the deferral of certain purchased power costs for which the means of recovery as not yet been established by the PUCO.

Transition Cost Amortization

JCP&L s and Met-Ed s regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of $164 million for JCP&L (recovered through NGC revenues) and $128 million for Met-Ed (recovered through CTC revenues). Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey and Pennsylvania (see Note 10).

(B) REVENUES AND RECEIVABLES

The Utilities principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Utilities retail customers are metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include distribution and retail electric sales to residential, commercial and industrial customers for the Utilities and retail and wholesale sales to customers for FES. There was no material concentration of receivables as of December 31, 2010 and 2009 with respect to any particular segment of FirstEnergy s customers. Billed and unbilled customer receivables as of December 31, 2010 and 2009 are shown below.

Customer Receivables	FE	FES	OE	CEI	TE[1]	JCP&L	Met-Ed	Penelec
				(In millions)				
December 31, 2010								
Billed	$ 752	$ 196	$ 81	$ 95	$	$ 178	$ 101	$ 82
Unbilled	640	170	96	89		145	78	67
Total	$ 1,392	$ 366	$ 177	$ 184	$	$ 323	$ 179	$ 149
December 31, 2009								
Billed	$ 725	$ 109	$ 101	$ 114	$ 1	$ 183	$ 110	$ 88
Unbilled	519	86	108	95		118	61	51
Total	$ 1,244	$ 195	$ 209	$ 209	$ 1	$ 301	$ 171	$ 139

(1) See Note 13 for a discussion of TE s accounts receivable financing arrangement with Centerior Funding Corporation.

(C) EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2010	2009	2008
	(In millions, except per share amounts)		
Earnings available to FirstEnergy Corp.	$ 784	$ 1,006	$ 1,342
Weighted average number of basic shares outstanding	304	304	304
Assumed exercise of dilutive stock options and awards	1	2	3
Weighted average number of diluted shares outstanding	305	306	307
Basic earnings per share of common stock	$ 2.58	$ 3.31	$ 4.41
Diluted earnings per share of common stock	$ 2.57	$ 3.29	$ 4.38

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which are adjusted to fair value), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. Property, plant and equipment balances as of December 31, 2010 and 2009 were as follows:

	December 31, 2010			**December 31, 2009**		
Property, Plant and Equipment	**Unregulated**	**Regulated**	**Total**	**Unregulated**	**Regulated**	**Total**
			(In millions)			
In service	$ 11,952	$ 17,499	$ 29,451	$ 10,935	$ 16,891	$ 27,826
Less accumulated depreciation	(4,229)	(6,951)	(11,180)	(4,699)	(6,698)	(11,397)
Net plant in service	$ 7,723	$ 10,548	$ 18,271	$ 6,236	$ 10,193	$ 16,429

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy s subsidiaries electric plant in 2010, 2009 and 2008 are shown in the following table:

	Annual Composite Depreciation Rate		
	2010	**2009**	**2008**
OE	2.9%	3.1%	3.1%
CEI	3.2	3.3	3.5
TE	3.3	3.3	3.6
Penn	2.2	2.4	2.4
JCP&L	2.4	2.4	2.3
Met-Ed	2.5	2.5	2.3
Penelec	2.5	2.6	2.5
FGCO	4.0	4.6	4.7
NGC	3.1	3.0	2.8

Asset Retirement Obligations

FirstEnergy recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FirstEnergy s current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant s current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset, as described further in Note 12.

(E) ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such an asset may not be recoverable. The recoverability of the long-lived asset is measured by comparing the long-lived asset s carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted future cash flows of the long-lived asset, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Impairments of long-lived assets recognized for the year ended December 31, 2010, are described further in Note 19.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit s goodwill is less than the carrying value of its goodwill.

FirstEnergy s goodwill primarily relates to its energy delivery services segment. FirstEnergy s aggregated reporting units are consistent with its operating segments energy delivery services and competitive energy. Goodwill is allocated to these operating segments based on the original purchase price allocation for acquisitions within the various reporting units. The goodwill allocated to competitive energy is insignificant to that segment and to FirstEnergy.

Annual impairment testing is conducted during the third quarter of each year and for 2010, 2009 and 2008 the analysis indicated no impairment of goodwill. For purposes of annual testing the estimated fair values of energy delivery services and the utilities were determined using a discounted cash flow approach.

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The discounted cash flow model of the reporting units, which are aggregated into operating segments, is based on the forecasted operating cash flow for the current year, projected operating cash flows for the next five years (determined using forecasted amounts as well as an estimated growth rate) and a terminal value beyond five years. Discounted cash flows consist of the operating cash flows for each reporting unit less an estimate for capital expenditures. The key assumptions incorporated in the discounted cash flow approach include growth rates, projected operating income, changes in working capital, projected capital expenditures, planned funding of pension plans, anticipated funding of nuclear decommissioning trusts, expected results of future rate proceedings and a discount rate equal to the assumed long term cost of capital. Cash flows may be adjusted to exclude certain non-recurring or unusual items. Reporting unit income, which excludes non-recurring or unusual items, was the starting point for determining operating cash flow and there were no non-recurring or unusual items excluded from the calculations of operating cash flow in any of the periods included in the determination of fair value.

Unanticipated changes in assumptions could have a significant effect on FirstEnergy s evaluation of goodwill. At the time of annual impairment testing, fair value would have to have declined in excess of 52% for energy delivery services to indicate a potential goodwill impairment. Fair value would have to have declined more than 26% for CEI, 64% for TE, 38% for JCP&L, 56% for Met-Ed and 57% for Penelec to indicate potential goodwill impairment.

A summary of the changes in goodwill for the three years ended December 31, 2010 is shown below by operating segment, which represent aggregated reporting units (see Note 15):

Goodwill	Energy Delivery Services	Competitive Energy Services	Consolidated
		(In millions)	
Balance as of December 31, 2007	$ 5,583	$ 24	$ 5,607
Adjustments related to GPU acquisitions	(32)		(32)
Balance as of December 31, 2008, 2009 and 2010	$ 5,551	$ 24	$ 5,575

A summary of the changes in FES and the Utilities goodwill for the three years ended December 31, 2010 is shown below.

Goodwill	FES	CEI	TE	JCP&L	Met-Ed	Penelec
			(In millions)			
Balance as of December, 31 2007	$ 24	$ 1,689	$ 501	$ 1,826	$ 424	$ 778
Adjustments related to GPU acquisition				(15)	(8)	(9)
Balance as of December, 31 2008, 2009 and 2010	$ 24	$ 1,689	$ 501	$ 1,811	$ 416	$ 769

FirstEnergy, FES and the Utilities, with the exception of Met-Ed, have no accumulated impairment charge as of December 31, 2010. Met-Ed has an accumulated impairment charge of $355 million, which was recorded in 2006.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for impairment. Investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security s fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other than temporary, the cost basis of the investment is written down to fair value. FirstEnergy recognizes in earnings the unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. In 2010, 2009 and 2008, FirstEnergy recognized $33 million, $62 million and $123 million, respectively, of other-than-temporary impairments. The fair values of FirstEnergy s investments are disclosed in Note 5(B).

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders equity except those resulting from transactions with stockholders and adjustments relating to noncontrolling interests. Accumulated other comprehensive income (loss), net of tax, included on FE s, FES and the Utilities Consolidated Balance Sheets as of December 31, 2010 and 2009, is comprised of the following:

Accumulated Other Comprehensive Income (Loss)	**FE**	**FES**	**OE**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)				
Net liability for unfunded retirement benefits	$ (1,492)	$ (127)	$ (180)	$ (153)	$ (49)	$ (253)	$ (141)	$ (164)
Unrealized gain on investments	7	6	1					
Unrealized gain (loss) on derivative hedges	(54)	1				(1)	(1)	
AOCL Balance, December 31, 2010	$ (1,539)	$ (120)	$ (179)	$ (153)	$ (49)	$ (254)	$ (142)	$ (164)
Net liability for unfunded retirement benefits	$ (1,341)	$ (91)	$ (164)	$ (138)	$ (50)	$ (242)	$ (143)	$ (162)
Unrealized gain on investments	2	2						
Unrealized loss on derivative hedges	(76)	(14)				(1)	(1)	
AOCL Balance, December 31, 2009	$ (1,415)	$ (103)	$ (164)	$ (138)	$ (50)	$ (243)	$ (144)	$ (162)

Other comprehensive income (loss) reclassified to net income during the three years ended December 31, 2010, 2009 and 2008 was as follows:

	FE	**FES**	**OE**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)				
2010								
Pension and other postretirement benefits	$ (67)	$ (3)	$ 1	$ (13)	$ (3)	$ (16)	$ (9)	$ (7)
Gain on investments	54	50	2		2			
Loss on derivative hedges	(35)	(24)						
	(48)	23	3	(13)	(1)	(16)	(9)	(7)
Income taxes (benefits) related to reclassification to net income	(19)	8	1	(5)		(6)	(4)	(3)
Reclassification to net income	$ (29)	$ 15	$ 2	$ (8)	$ (1)	$ (10)	$ (5)	$ (4)
2009								
Pension and other postretirement benefits	$ (78)	$ (3)	$ (5)	$ (11)	$ (2)	$ (18)	$ (11)	$ (5)
Gain on investments	157	139	10		7			
Loss on derivative hedges	(67)	(27)						
	12	109	5	(11)	5	(18)	(11)	(5)
Income taxes (benefits) related to reclassification to net income	4	41	2	(4)	2	(8)	(5)	(2)

Reclassification to net income	$ 8	$ 68	$ 3	$ (7)	$ 3	$ (10)	$ (6)	$ (3)
2008								
Pension and other postretirement benefits	$ 80	$ 7	$ 16	$ 1	$	$ 14	$ 9	$ 14
Gain on investments	40	31	9		1			
Loss on derivative hedges	(19)	(3)						
	101	35	25	1	1	14	9	14
Income taxes related to reclassification to net income	41	14	10			6	4	6
Reclassification to net income	$ 60	$ 21	$ 15	$ 1	$ 1	$ 8	$ 5	$ 8

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3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. FirstEnergy s funding policy is based on actuarial computations using the projected unit credit method. On September 2, 2009, the Utilities and ATSI made a combined $500 million voluntary contribution to their qualified pension plan. Due to the significance of the voluntary contribution, FirstEnergy elected to remeasure its qualified pension plan as of August 31, 2009. FirstEnergy intends to voluntarily contribute $250 million to its pension plan in 2011.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2008, FirstEnergy amended the OPEB plan effective in 2010 to limit the monthly contribution for pre-1990 retirees. On June 2, 2009, FirstEnergy amended its health care benefits plan for all employees and retirees eligible to participate in that plan. The amendment, which reduces future health care coverage subsidies paid by FirstEnergy on behalf of participants, triggered a remeasurement of FirstEnergy s other postretirement benefit plans as of May 31, 2009. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

In the third quarter of 2009, FirstEnergy incurred a $13 million net postretirement benefit cost (including amounts capitalized) related to a liability created by the VERO offered by FirstEnergy to qualified employees. The special termination benefits of the VERO included additional health care coverage subsidies paid by FirstEnergy to those qualified employees who elected to retire. A total of 715 employees accepted the VERO.

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Obligations and Funded Status As of December 31	**Pension Benefits 2010**	**Pension Benefits 2009**	**Other Benefits 2010**	**Other Benefits 2009**
		(In millions)		
Change in benefit obligation				
Benefit obligation as of January 1	$ 5,392	$ 4,700	$ 823	$ 1,189
Service cost	99	91	10	12
Interest cost	314	317	45	64
Plan participants contributions			30	29
Plan amendments	16	6		(408)
Special termination benefits				13
Medicare retiree drug subsidy			7	20
Actuarial (gain) loss	343	648	56	23
Benefits paid	(306)	(370)	(110)	(119)
Benefit obligation as of December 31	$ 5,858	$ 5,392	$ 861	$ 823
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,399	$ 3,752	$ 467	$ 440
Actual return on plan assets	440	508	52	62
Company contributions	11	509	59	55
Plan participants contributions			30	29
Benefits paid	(306)	(370)	(110)	(119)
Fair value of plan assets as of December 31	$ 4,544	$ 4,399	$ 498	$ 467
Funded Status				
Qualified plan	$ (1,076)	$ (787)		
Non-qualified plans	(238)	(206)		
Funded Status	$ (1,314)	$ (993)	$ (363)	$ (356)
Accumulated benefit obligation	**$ 5,469**	**$ 5,036**		
Amounts Recognized on the Balance Sheet				
Current liabilities	$ (11)	$ (10)	$	$
Noncurrent liabilities	(1,303)	(983)	(363)	(356)
Net liability as of December 31	$ (1,314)	$ (993)	$ (363)	$ (356)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 76	$ 67	$ (952)	$ (1,145)
Actuarial loss	2,554	2,486	718	756

Net amount recognized	$ 2,630	$ 2,553	$ (234)	$ (389)
Assumptions Used to Determine Benefit Obligations as of December 31				
Discount rate	5.50%	6.00%	5.00%	5.75%
Rate of compensation increase	5.20%	5.20%		
Allocation of Plan Assets As of December 31				
Equity securities	28%	39%	47%	51%
Bonds	50	49	45	46
Absolute return strategies	11		3	
Real estate	6	6	2	1
Private equities	4	5	1	1
Cash	1	1	2	1
Total	100%	100%	100%	100%

Estimated 2011 Amortization of Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$ 14	$ (193)
Actuarial loss	$ 194	$ 57

	Pension Benefits			Other Benefits		
Components of Net Periodic Benefit Costs	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
			(In millions)			
Service cost	$ 99	$ 91	$ 87	$ 10	$ 12	$ 19
Interest cost	314	317	299	45	64	74
Expected return on plan assets	(361)	(343)	(463)	(36)	(36)	(51)
Amortization of prior service cost	13	13	13	(193)	(175)	(149)
Amortization of net actuarial loss	187	179	8	60	61	47
Net periodic cost	$ 252	$ 257	$ (56)	$ (114)	$ (74)	$ (60)

FES and the Utilities shares of the net pension and OPEB asset (liability) as of December 31, 2010 and 2009 are as follows:

	Pension Benefits		Other Benefits	
Net Pension and OPEB Asset (Liability)	**2010**	**2009**	**2010**	**2009**
		(In millions)		
FES	$ (488)	$ (361)	$ (36)	$ (19)
OE	29	30	(66)	(74)
CEI	(22)	(13)	(62)	(59)
TE	(21)	(15)	(46)	(47)
JCP&L	(106)	(77)	(70)	(56)
Met-Ed	(6)	6	(19)	(28)
Penelec	(99)	(79)	(85)	(84)

FES and the Utilities shares of the net periodic pension and OPEB costs for the three years ended December 31, 2010 are as follows:

	Pension Benefits			Other Benefits		
Net Periodic Pension and OPEB Costs	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
			(In millions)			
FES	$ 84	$ 71	$ 15	$ (27)	$ (15)	$ (7)
OE	15	23	(26)	(25)	(14)	(7)
CEI	20	17	(5)	(6)		2
TE	7	6	(3)	(1)	2	4
JCP&L	25	31	(15)	(7)	(6)	(16)
Met-Ed	10	18	(10)	(8)	(4)	(10)
Penelec	19	16	(13)	(9)	(4)	(13)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2010	2009	2008	Other Benefits 2010	2009	2008

Weighted-average discount rate	6.00%	7.00%	6.50%	5.75%	7.00%	6.50%
Expected long-term return on plan assets	8.50%	9.00%	9.00%	8.50%	9.00%	9.00%
Rate of compensation increase	5.20%	5.20%	5.20%			

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Accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by accounting guidance are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 assets include registered investment companies, common stocks, publicly traded real estate investment trusts and certain shorter duration, more liquid fixed income securities. Registered investment companies and common stocks are stated at fair value as quoted on a recognized securities exchange and are valued at the last reported sales price on the last business day of the plan year. Market values for real estate investment trusts and certain fixed income securities are based on daily quotes available on public exchanges as with other publicly traded equity and fixed income securities.

Level 2 Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 2 investments include common collective trusts, certain real estate investment trusts, and fixed income assets. Common collective trusts are not available in an exchange and active market; however, the fair value is determined based on the underlying investments as traded in an exchange and active market.

Level 3 Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value in addition to the use of independent appraisers estimates of fair value on a periodic basis typically determined quarterly but no less than annually. Assets in this category include private equity, limited partnership, certain real estate trusts and fixed income securities. The fixed income securities market values are based in part on quantitative models and on observing market value ascertained through timely trades for securities that are similar to the ones being valued.

As of December 31, 2010 and 2009, the pension investments measured at fair value were as follows:

	December 31, 2010				Asset
	Level 1	Level 2	Level 3	Total	Allocation
		(In millions)			
Cash and short-term securities	$	$ 72	$	$ 72	1%
Equity investments					
Domestic	342	189		531	12%
International	118	615		733	16%
Fixed income					
Government bonds		722		722	16%
Corporate bonds		1,414		1,414	31%
Distressed debt		97		97	2%
Mortgaged-backed securities (non-government)		52		52	1%
Alternatives					
Hedge funds		497		497	11%
Private equity funds			119	119	4%
Real estate funds	2		282	284	6%
	$ 462	$ 3,658	$ 401	$ 4,521	100%

	December 31, 2009				Asset
	Level 1	Level 2	Level 3	Total	Allocation
		(In millions)			
Cash and short-term securities	$	$ 337	$	$ 337	7%
Equity investments					
Domestic	447	790		1,237	28%
International	131	204		335	8%
Mutual funds	159			159	4%
Fixed income					
Government bonds		254		254	6%
Corporate bonds		1,580		1,580	35%
Distressed debt		92		92	2%
Mortgaged-backed securities (non-government)		2		2	1%
Alternatives					
Private equity funds			137	137	3%
Real estate funds	1	4	241	246	6%
	$ 738	$ 3,263	$ 378	$ 4,379	100%

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2010 and 2009:

	Private Equity Funds	Real Estate Funds
Balance as of January 1, 2009	$ 74	$ 342
Actual return on plan assets:		
Unrealized gains (losses)	6	(104)
Realized gains (losses)	1	(1)
Purchases, sales and settlements	12	4
Transfers in (out)	44	
Balance as of December 31, 2009	137	241
Actual return on plan assets:		
Unrealized gains	1	45
Realized gains (losses)	11	(3)
Purchases, sales and settlements	(28)	(1)
Transfers in (out)	(2)	
Balance at December 31, 2010	$ 119	$ 282

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As of December 31, 2010 and 2009, the other postretirement benefit investments measured at fair value were as follows:

	December 31, 2010				Asset
	Level 1	Level 2	Level 3	Total	Allocation
		(In millions)			
Cash and short-term securities	$	$ 16	$	$ 16	2%
Equity investment					
Domestic	178	6		184	36%
International	20	19		39	9%
Mutual funds	7	2		9	2%
Fixed income					
U.S. treasuries		27		27	5%
Government bonds		143		143	28%
Corporate bonds		55		55	10%
Distressed debt		3		3	1%
Mortgage-backed securities (non-government)		4		4	1%
Alternatives					
Hedge funds		15		15	3%
Private equity funds			3	3	1%
Real estate funds			9	9	2%
	$ 205	$ 290	$ 12	$ 507	100%

	December 31, 2009				Asset
	Level 1	Level 2	Level 3	Total	Allocation
		(In millions)			
Cash and short-term securities	$	$ 19	$	$ 19	4%
Equity investment					
Domestic	180	23		203	43%
International	15	6		21	4%
Mutual funds	10	2		12	3%
Fixed income					
U.S. treasuries		20		20	4%
Government bonds		123		123	26%
Corporate bonds		56		56	12%
Distressed debt		3		3	1%
Mortgage-backed securities (non-government)		3		3	1%
Alternatives					
Private equity funds			4	4	1%
Real estate funds			7	7	1%
	$ 205	$ 255	$ 11	$ 471	100%

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The following table provides a reconciliation of changes in the fair value of postretirement benefit investments classified as Level 3 in the fair value hierarchy during 2010 and 2009:

	Private Equity Funds	Real Estate Funds
	(in millions)	
Balance as of January 1, 2009	$ 2	$ 10
Actual return on plan assets:		
Unrealized gains (losses)		(3)
Realized gains (losses)		
Purchases, sales and settlements	1	
Transfers in (out)	1	
Balance as of December 31, 2009	4	7
Actual return on plan assets:		
Unrealized gains		
Realized gains (losses)		2
Purchases, sales and settlements	(1)	
Transfers in (out)		
Balance at December 31, 2010	$ 3	$ 9

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy s pension trusts. The long-term rate of return is developed considering the portfolio s asset allocation strategy.

FirstEnergy generally employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

FirstEnergy s target asset allocations for its pension and OPEB portfolio for 2010 and 2009 are shown in the following table:

	Target Asset Allocations	
	2010	2009
Equities	21%	58%
Fixed income	50	30
Absolute return strategies	21	
Real estate	6	8
Private equity	2	4

Total	100%	100%

Assumed Health Care Cost Trend Rates **As of December 31**	**2010**	**2009**
Health care cost trend rate assumed (pre/post-Medicare)	8.0-9.0%	8.5-10%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2016-2018	2016-2018

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total of service and interest cost	$ 2	$ (2)
Effect on accumulated postretirement benefit obligation	$ 22	$ (20)

Taking into account estimated employee future service, FirstEnergy expects to make the following pension benefit payments from plan assets and other benefit payments, net of the Medicare subsidy and participant contributions:

	Pension Benefits	Other Benefits
	(in millions)	
2011	$ 320	$ 88
2012	332	76
2013	344	61
2014	367	63
2015	381	61
Years 2016-2020	2,068	297

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs LTIP, EDCP, ESOP and DCPD.

(A) LTIP

FirstEnergy s LTIP includes four stock-based compensation programs restricted stock, restricted stock units, stock options and performance shares.

Under FirstEnergy s LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2010, 7.2 million shares were available for future awards.

FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2010, 2009 and 2008 were $11 million, $9 million and $43 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded in stockholders equity and reported as an other financing activity on the Consolidated Statements of Cash Flows.

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Restricted Stock and Restricted Stock Units

Eligible employees receive awards of FirstEnergy common stock or stock units subject to restrictions. Those restrictions lapse over a defined period of time or based on performance. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted common stock grants under the LTIP were as follows:

	2010	2009	2008
Restricted common shares granted	71,752	73,255	82,607
Weighted average market price	$ 38.43	$ 43.68	$ 68.98
Weighted average vesting period (years)	4.74	4.42	5.03
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during 2010 was as follows (forfeitures were not material):

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2010	648,293	$ 50.39
Nonvested as of December 31, 2010	475,914	51.26
Granted in 2010	71,752	38.43
Vested in 2010	292,152	38.75

FirstEnergy grants two types of restricted stock unit awards: discretionary-based and performance-based. With the discretionary-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in each agreement. With the performance-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in the agreement subject to adjustment based on FirstEnergy s stock performance.

	2010	2009	2008
Restricted common shares units granted	511,418	533,399	450,683
Weighted average vesting period (years)	3.00	3.00	3.14

Vesting activity for restricted stock units during 2010 was as follows (forfeitures were not material):

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2010	1,489,187	$ 54.81
Nonvested as of December 31, 2010	1,402,108	48.40
Granted in 2010	511,418	37.13
Vested in 2010	579,736	38.83

Compensation expense recognized in 2010, 2009 and 2008 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $22 million, $25 million and $29 million, respectively.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activities under FirstEnergy stock option programs during 2010 were as follows:

Stock Option Activities	Number of Shares	Weighted Average Grant-Date Fair value
Balance, January 1, 2010 (3,074,626 options exercisable)	3,074,626	$ 34.69
Options granted		
Options exercised	180,460	26.86
Options forfeited	5,100	21.61
Balance, December 31, 2010 (2,889,066 options exercisable)	2,889,066	$ 35.18

Options outstanding and range of exercise price as of December 31, 2010 were as follows:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life
$29.50-29.71	894,054	$ 29.66	1.77
$34.45-39.46	1,995,012	$ 37.66	2.67
Total	2,889,066	$ 35.18	2.39

FirstEnergy reduced its use of stock options beginning in 2005 and increased its use of performance-based, restricted stock units. As a result, all unvested stock options vested in 2008. No compensation expense was recognized for stock options during 2010 and 2009, and compensation expense in 2008 was not material. Cash received from the exercise of stock options in 2010, 2009 and 2008 was $6 million, $7 million and $74 million, respectively.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy s common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock performance to a composite of peer companies. Compensation expense (income) recognized for performance shares during 2010, 2009 and 2008, net of amounts capitalized, totaled approximately ($4) million, $3 million and $8 million, respectively. During 2010, no cash was paid to settle performance shares due to certain criteria not being met for the previous three-year vesting period. Cash used to settle performance shares in 2009 and 2008 was $15 million and $14 million, respectively.

(B) ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy s 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP.

In 2008 and 2009, shares of FirstEnergy common stock were purchased on the market and contributed to participants accounts. Total ESOP-related compensation expenses in 2010, 2009 and 2008, net of amounts capitalized and dividends on common stock were $30 million, $36 million and $40 million, respectively.

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units or into an unfunded retirement cash account. Through December 31, 2010, covered employees received an additional 20% premium in the form of stock units based on the amount allocated to the FirstEnergy stock account. During 2010, the EDCP was amended to cease the 20% stock premium with respect to annual and long-term incentive awards earned during any calendar years that commence on or after January 1, 2011. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Compensation expense (income) recognized on EDCP stock units, net of amounts capitalized, in 2010, 2009 and 2008 was ($3) million, ($0.2) million and ($13) million, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. Funds deferred into the stock account through December 31, 2010, receive a 20% match to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. During 2010, the DCPD was amended to cease the 20% match feature with respect to director s fees earned for service performed during any calendar years that commence on or after January 1, 2011. DCPD expenses recognized in 2010, 2009 and 2008 was $4 million, $3 million and $3 million, respectively. The net liability recognized for DCPD of approximately $5 million as of December 31, 2010, 2009 and 2008 is included in the caption Retirement benefits on the Consolidated Balance Sheets.

Of the 1.7 million stock units authorized under the EDCP and DCPD, 1,239,415 stock units were available for future awards as of December 31, 2010.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

(A) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption short-term borrowings. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as of December 31, 2010 and 2009:

	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy (Consolidated)	$ 13,928	$ 14,845	$ 13,853	$ 14,602
FES	4,279	4,403	4,324	4,406
OE	1,159	1,321	1,169	1,299
CEI	1,853	2,035	1,873	2,032
TE	600	653	600	638
JCP&L	1,810	1,962	1,840	1,950
Met-Ed	742	821	842	909
Penelec	1,120	1,189	1,144	1,177

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy, FES and the Utilities.

(B) INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities, available-for-sale securities and notes receivable. FES and the Utilities periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold an equity investment until recovery and then consider, among other factors, the duration and the extent to which the security s fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FES and the Utilities consider their intent to hold the security, the likelihood that they will be required to sell the security before recovery of their cost basis, and the likelihood of recovery of the security s entire amortized cost basis.

Available-For-Sale Securities

FES and the Utilities hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are considered as available-for-sale at fair market value. FES and the Utilities have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts as of December 31, 2010 and 2009:

	December 31, 2010[(1)]				December 31, 2009[(2)]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities								
FirstEnergy	$ 1,699	$ 31	$	$ 1,730	$ 1,727	$ 22	$	$ 1,749
FES	980	13		993	1,043	3		1,046
OE	123	1		124	55			55
TE	42			42	72			72
JCP&L	281	9		290	271	9		280
Met-Ed	127	4		131	120	5		125
Penelec	145	4		149	166	5		171
Equity securities								
FirstEnergy	$ 268	$ 69	$	$ 337	$ 252	$ 43	$	$ 295
JCP&L	80	17		97	74	11		85
Met-Ed	125	35		160	117	23		140
Penelec	63	16		79	61	9		70

(1) Excludes cash balances: FirstEnergy $193 million; FES $153 million; OE $3 million; TE $34 million; JCP&L $3 million; Met-Ed $(3) million and Penelec $4 million.

(2) Excludes cash balances: FirstEnergy $137 million; FES $43 million; OE $66 million; TE $2 million; JCP&L $3 million and Penelec $23 million.

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Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2010, 2009 and 2008 were as follows:

December 31, 2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 3,172	$ 126	$ 107	$ 79
FES	1,927	92	75	47
OE	83	2		3
TE	126	3	1	2
JCP&L	411	10	10	14
Met-Ed	460	13	14	7
Penelec	165	6	7	6

December 31, 2009	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 2,229	$ 226	$ 155	$ 60
FES	1,379	199	117	27
OE	132	11	4	4
TE	169	7	1	2
JCP&L	397	6	12	14
Met-Ed	68	2	13	7
Penelec	84	1	8	6

December 31, 2008	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,657	$ 115	$ 237	$ 76
FES	951	99	184	37
OE	121	11	9	5
TE	38	1		3
JCP&L	248	1	17	14
Met-Ed	181	2	17	9
Penelec	118	1	10	8

Unrealized gains applicable to the decommissioning trusts of FES, OE and TE are recognized in OCI since fluctuations in fair value will eventually impact earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting. Net unrealized gains and losses are recorded as regulatory assets or liabilities since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund s custodian or managers and their parents or subsidiaries.

During 2010, 2009 and 2008, FirstEnergy recognized $55 million, $176 million and $63 million of net realized gains resulting from the sale of securities held in nuclear decommissioning trusts.

Held-To-Maturity Securities
The following table provides the amortized cost basis, unrealized gains and losses, and approximate fair values of investments in held-to-maturity securities as of December 31, 2010 and 2009:

	December 31, 2010				December 31, 2009			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt Securities								
FirstEnergy	$ 476	$ 91	$	$ 567	$ 544	$ 72	$	$ 616
OE	190	51		241	217	29		246
CEI	340	41		381	389	43		432

Investments in emission allowances, employee benefits and cost and equity method investments totaling $259 million as of December 31, 2010, and $264 million as of December 31, 2009, are not required to be disclosed and are excluded from the amounts reported above.
Notes Receivable
The table below provides the approximate fair value and related carrying amounts of notes receivable as of December 31, 2010 and 2009. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2013 to 2021.

	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Notes Receivable				
FirstEnergy	$ 7	$ 8	$ 36	$ 35
FES			2	1
TE	104	118	124	141

(C) RECURRING FAIR VALUE MEASUREMENTS
Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. A fair value hierarchy has been established that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:
Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. FirstEnergy s Level 1 assets and liabilities primarily consist of exchange-traded derivatives and equity securities listed on active exchanges that are held in various trusts.
Level 2 Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. FirstEnergy s Level 2 assets and liabilities consist primarily of investments in debt securities held in various trusts and commodity forwards. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category may include non-exchange-traded derivatives such as

forwards and certain interest rate swaps.

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Level 3   Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the long term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate FirstEnergy management. Level 3 instruments include those that may be more structured or otherwise tailored to customers needs. FirstEnergy s Level 3 instruments consist exclusively of NUG contracts.

FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The determination of the fair value measures takes into consideration various factors. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

The following tables set forth financial assets and financial liabilities that are accounted for at fair value by level within the fair value hierarchy as of December 31, 2010 and 2009. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FirstEnergy s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair valuation of assets and liabilities and their placement within the fair value hierarchy levels. Transfers between levels are recognized at the end of the reporting period. During 2010, there were no significant transfers between Level 1, Level 2 and Level 3.

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FirstEnergy Corp.

The following tables provide the fair value measurement amounts for assets and liabilities recorded on FirstEnergy s Consolidated Balance Sheets at fair value at December 31, 2010 and 2009:

December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 597	$	$ 597
Derivative assets commodity contracts		250		250
Derivative assets NUG contracts(1)			122	122
Equity securities(2)	338			338
Foreign government debt securities		149		149
U.S. government debt securities		595		595
U.S. state debt securities		379		379
Other(4)		219		219
Total assets	$ 338	$ 2,189	$ 122	$ 2,649
Liabilities				
Derivative liabilities commodity contracts	$	$ (348)	$	$ (348)
Derivative liabilities NUG contracts(1)			(466)	(466)
Total liabilities	$	$ (348)	$ (466)	$ (814)
Net assets (liabilities)(3)	$ 338	$ 1,841	$ (344)	$ 1,835

December 31, 2009	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 484	$	$ 484
Derivative assets commodity contracts		34		34
Derivative assets NUG contracts(1)			200	200
Equity securities(2)	295			295
Foreign government debt securities		279		279
U.S. government debt securities		558		558
U.S. state debt securities		478		478
Other(4)		75		75
Total assets	$ 295	$ 1,908	$ 200	$ 2,403
Liabilities				
Derivative liabilities commodity contracts	$ (11)	$ (224)	$	$ (235)
Derivative liabilities NUG contracts(1)			(643)	(643)
Total liabilities	$ (11)	$ (224)	$ (643)	$ (878)

Net assets (liabilities)[3]	$	284	$	1,684	$	(443)	$	1,525

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(7) million and $21 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

(4) Primarily consists of cash and cash equivalents.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by the Utilities and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts[(1)]	Derivative Liability NUG Contracts[(1)]	Net NUG Contracts[(1)]
		(In millions)	
January 1, 2010 Balance	$ 200	$ (643)	$ (443)
Realized gain (loss)			
Unrealized gain (loss)	(71)	(110)	(181)
Purchases			
Issuances			
Sales			
Settlements	(7)	287	280
Transfers in (out) of Level 3			
December 31, 2010 Balance	$ 122	$ (466)	$ (344)
January 1, 2009 Balance	$ 434	$ (765)	$ (331)
Realized gain (loss)			
Unrealized gain (loss)	(234)	(236)	(470)
Purchases			
Issuances			
Sales			
Settlements		358	358
Transfers in (out) of Level 3			
December 31, 2009 Balance	$ 200	$ (643)	$ (443)

(1) Changes in the fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

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FirstEnergy Solutions Corp.

The following tables provide the fair value measurement amounts for assets and liabilities recorded on FES Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 528	$	$ 528
Derivative assets commodity contracts		241		241
Foreign government debt securities		147		147
U.S. government debt securities		308		308
U.S. state debt securities		6		6
Other(2)		148		148
Total assets	$	$ 1,378	$	$ 1,378
Liabilities				
Derivative liabilities commodity contracts	$	$ (348)	$	$ (348)
Total liabilities	$	$ (348)	$	$ (348)
Net assets (liabilities)(1)	$	$ 1,030	$	$ 1,030

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 443	$	$ 443
Derivative assets commodity contracts		15		15
Foreign government debt securities		279		279
U.S. government debt securities		306		306
U.S. state debt securities		15		15
Other(2)		29		29
Total assets	$	$ 1,087	$	$ 1,087
Liabilities				
Derivative liabilities commodity contracts	$ (11)	$ (224)	$	$ (235)
Total liabilities	$ (11)	$ (224)	$	$ (235)
Net assets (liabilities)(1)	$ (11)	$ 863	$	$ 852

(1) Excludes $7 million and $15 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

(2) Primarily consists of cash and cash equivalents.

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Ohio Edison Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on OE s Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
U.S. government debt securities	$	$ 124	$	$ 124
Other		2		2
Total assets(1)	$	$ 126	$	$ 126

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
U.S. government debt securities	$	$ 118	$	$ 118
Other		2		2
Total assets(1)	$	$ 120	$	$ 120

(1) Excludes $1 million as of December 31, 2010 and 2009 of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Toledo Edison Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on TE s Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 7	$	$ 7
U.S. government debt securities		33		33
U.S. state debt securities		1		1
Other(2)		35		35
Total assets(1)	$	$ 76	$	$ 76

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$	$	$
U.S. government debt securities		72		72
Other				
Total assets(1)	$	$ 72	$	$ 72

(1) Excludes $2 million as of December 31, 2009 of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

(2) Primarily consists of cash and cash equivalents.

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Jersey Central Power & Light Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on JCP&L s Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 23	$	$ 23
Derivative assets commodity contracts		2		2
Derivative assets NUG contracts[1]			6	6
Equity securities[2]	96			96
U.S. government debt securities		33		33
U.S. state debt securities		236		236
Other		4		4
Total assets	$ 96	$ 298	$ 6	$ 400
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (233)	$ (233)
Total liabilities	$	$	$ (233)	$ (233)
Net assets (liabilities)[3]	$ 96	$ 298	$ (227)	$ 167

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$	$ 15	$	$ 15
Derivative assets commodity contracts		5		5
Derivative assets NUG contracts[1]			8	8
Equity securities[2]	87			87
U.S. government debt securities		23		23
U.S. state debt securities		230		230
Other		12		12
Total assets	$ 87	$ 285	$ 8	$ 380
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (399)	$ (399)
Total liabilities	$	$	$ (399)	$ (399)
Net assets (liabilities)[3]	$ 87	$ 285	$ (391)	$ (19)

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(3) million as of December 31, 2010 of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts[(1)]	Derivative Liability NUG Contracts[(1)]	Net NUG Contracts[(1)]
		(In millions)	
January 1, 2010 Balance	$ 8	$ (399)	$ (391)
Realized gain (loss)			
Unrealized gain (loss)	(1)	36	35
Purchases			
Issuances			
Sales			
Settlements	(1)	130	129
Transfers in (out) of Level 3			
December 31, 2010 Balance	$ 6	$ (233)	$ (227)
January 1, 2009 Balance	$ 14	$ (531)	$ (517)
Realized gain (loss)			
Unrealized gain (loss)	(6)	(36)	(42)
Purchases			
Issuances			
Sales			
Settlements		168	168
Transfers in (out) of Level 3			
December 31, 2009 Balance	$ 8	$ (399)	$ (391)

(1) Changes in the fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

Metropolitan Edison Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on Met-Ed s Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 32	$	$ 32
Derivative assets commodity contracts		5		5
Derivative assets NUG contracts[1]			112	112
Equity securities[2]	160			160
Foreign government debt securities		1		1
U.S. government debt securities		88		88
U.S. state debt securities		2		2
Other		14		14
Total assets	$ 160	$ 142	$ 112	$ 414
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (116)	$ (116)
Total liabilities	$	$	$ (116)	$ (116)
Net assets (liabilities)[3]	$ 160	$ 142	$ (4)	$ 298

December 31, 2009	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets				
Corporate debt securities	$	$ 20	$	$ 20
Derivative assets commodity contracts		9		9
Derivative assets NUG contracts[1]			176	176
Equity securities[2]	133			133
U.S. government debt securities		30		30
U.S. state debt securities		82		82
Other		2		2
Total assets	$ 133	$ 143	$ 176	$ 452
Liabilities				
Derivative liabilities NUG contracts[1]	$	$	$ (143)	$ (143)
Total liabilities	$	$	$ (143)	$ (143)
Net assets (liabilities)[3]	$ 133	$ 143	$ 33	$ 309

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(9) million and $1 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by Met-Ed and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts(1)	Derivative Liability NUG Contracts(1)	Net NUG Contracts(1)
		(In millions)	
January 1, 2010 Balance	$ 176	$ (143)	$ 33
Realized gain (loss)			
Unrealized gain (loss)	(59)	(38)	(97)
Purchases			
Issuances			
Sales			
Settlements	(5)	65	60
Transfers in (out) of Level 3			
December 31, 2010 Balance	$ 112	$ (116)	$ (4)
January 1, 2009 Balance	$ 300	$ (150	