FirstEnergy

2009 Annual Report

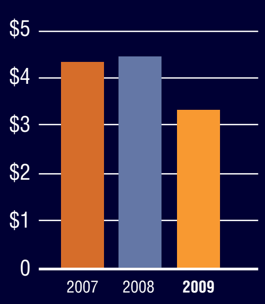
Financial Highlights

Key accomplishments:

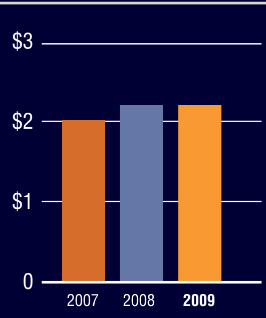
- Maintained dividend of $2.20 per share
- Enhanced our liquidity position
- Generated $2.5 billion in cash from operations
- Reduced capital spending by $380 million and operation and maintenance expenses by $344 million
- Completed the transition to competitive markets for generation in Ohio
- Delivered top-decile bulk transmission performance while continuing to improve distribution reliability
- Secured a 20-year license extension from the Nuclear Regulatory Commission for the Beaver Valley Power Station

(Dollars in millions, except per share amounts)	2009	2008
Total revenues	$12,967	$13,627
Net income	$ 990	$ 1,339
Basic earnings per common share	$ 3.31	$ 4.41
Diluted earnings per common share	$ 3.29	$ 4.38
Dividends paid per common share	$ 2.20	$ 2.20
Book value per common share	$ 28.08	$ 27.17
Net cash from operating activities	$ 2,465	$ 2,224

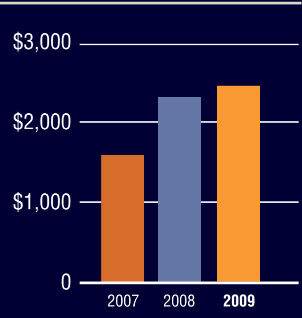
Basic Earnings Per Common Share



Dividends Paid Per Common Share



Net Cash from Operating Activities (millions)



On the cover: *The 200-foot-tall "Great Wall" of ductwork is part of the $1.8 billion Air Quality Compliance project that is nearing completion at our W.H. Sammis Plant in Stratton, Ohio.*

Message to Shareholders

Anthony J. Alexander
President and Chief Executive Officer

Despite a difficult economy and mild weather in 2009, we strengthened our competitive position, enhanced the reliability and efficiency of our regulated operations, and improved the environmental performance of our generating fleet.

And, in February of this year, we announced plans to combine with Allegheny Energy, Inc. – a move consistent with our strategy to build a balanced, integrated and diversified portfolio of assets. We believe this transaction is a natural fit of two companies with adjacent geographic footprints. It would create a leading regional energy company serving more than six million customers in seven states, enabling us to increase our generating capacity by 70 percent and our regulated customer base by 35 percent.

The combined company would have a total generating capacity of approximately 24,000 megawatts (MW), anchored by a fleet of efficient, supercritical coal units and non-emitting nuclear plants. We also expect that the merger will create significant economies of scale as we share best practices across the new organization.

Simply put, this combination provides a better platform for future growth than we would have been able to achieve on a stand-alone basis.

We expect to secure the necessary approvals to complete this transaction in the first half of 2011.

Delivering Results in Difficult Times

Despite weak demand for power and lower electricity prices, we produced solid financial results in 2009. We delivered basic non-GAAP* earnings per share of $3.77 and generated nearly $2.5 billion in cash from operations.

We also enhanced our financial strength and flexibility by successfully completing initial long-term debt offerings of $1.5 billion for our competitive subsidiary, FirstEnergy Solutions (FES), and $400 million for our American Transmission Systems, Inc. (ATSI) subsidiary. And, we retired $1.25 billion of FirstEnergy holding company debt while preserving our common stock dividend.

AQC

Sammis Plant Air Quality Compliance (AQC) Project

New environmental controls are expected to be operating on all seven units at the W.H. Sammis Plant in Stratton, Ohio, by the end of this year. Designed to further reduce the plant's sulfur dioxide and nitrogen oxides emissions, it is one of the largest environmental retrofit projects in the nation.

Signal

** Please refer to page 8 for an explanation of this term.*

In addition, we reached two significant milestones in our competitive business – completing the transition to open markets for generation in Ohio and securing a 20-year license extension from the Nuclear Regulatory Commission for our Beaver Valley Power Station.

We also took steps during this period of low demand to better position our generating fleet for the expected increase in demand for electricity. For example, we accelerated the timing of capital investments and operating improvements at several of our power plants. We completed extended refueling and maintenance outages at our nuclear facilities. And, by improving equipment reliability and reducing unplanned outages at Beaver Valley and our Davis-Besse Nuclear Power Station, we achieved top industry performance in these two areas at both plants. In addition, we moved closer toward completion of the massive, $1.8 billion environmental retrofit at our Sammis Plant.

On the regulated side of our business, we achieved top-decile bulk transmission performance and our fifth consecutive year of improved distribution reliability. In fact, we posted our best results since 2001 as we further reduced the number of customers affected by outages and the average length of time a customer is without service during the year. This progress reflects the dedicated efforts of our employees as well as the targeted investments we've made in recent years to enhance the reliability of our energy delivery system.

In Ohio, we received approvals from the Public Utilities Commission of Ohio for a distribution rate increase and for our Electric Security Plan (ESP). Among other benefits, these decisions allow for recovery of our incremental costs related to storm restoration efforts and uncollectible expenses, and establish a new charge for distribution service improvements. The ESP set the stage for an auction conducted in May that, for the first time, established competitive electric generation supply and pricing for our Ohio customers.

In Pennsylvania, we obtained approval from the state's Public Utility Commission for plans filed by our Met-Ed and Penelec utilities to secure generation from competitive markets to serve customers beginning January 1, 2011. This approval is an important step toward completing the transition to fully competitive markets for our customers in Pennsylvania.

Peak

Signal Peak Coal Mine *In Montana, a 35-mile rail link between the mine and the main line junction was completed last year to ensure reliable, high-volume movement of coal to eastern and western U.S. coal markets. Our equity investment in Signal Peak is expected to provide a fuel supply that offers the environmental benefits of cleaner-burning western coal, but with a higher heat content than our current mix of coals.*

Burger

Burger Plant Conversion to Biomass *Retrofitting the R.E. Burger Plant in Shadyside, Ohio, for biomass will expand the Company's already diverse generation portfolio and support state mandates for renewable energy.*

FirstEnergy reached another important milestone in 2009 by receiving approval from the Federal Energy Regulatory Commission to consolidate our ATSI subsidiary into PJM Interconnection, LLC. The move is expected to provide us with the operating efficiencies of a single regional transmission organization, and customers of our Ohio utilities and Penn Power with the benefits of a more fully developed retail choice market.

Our transmission operations also are expected to benefit considerably from the merger with Allegheny Energy. We expect improved efficiencies and coordination as a result of the new company's scale and scope. Also, we anticipate that major projects currently planned or under way at Allegheny Energy will enable us to grow our transmission business in the years ahead.

Strengthening
Our Competitive Position

During the year, FES made significant progress in effectively deploying and committing its generating output to end-use customers.

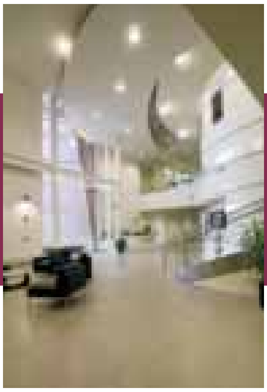
Since the Ohio power auction was conducted in May, our competitive subsidiary has pursued an overall strategy that integrates the strength of its generating fleet with a strong and targeted sales effort. For example, FES is locking in long-term sales contracts with governmental aggregation groups serving residential and small commercial customers within our Ohio utilities' service areas, as well as contracts with large commercial and industrial customers throughout our region. And, we increased our market share from 51 percent as of June 1, to more than 80 percent of our Ohio utilities' load by the end of 2009.

FES' success has been achieved, in part, through its innovative "Powering Our Communities" program. This effort extends governmental aggregation arrangements with price discounts for up to nine years, while providing immediate economic assistance to local communities during the recession. Under this program, FES entered into a long-term agreement with the Northeast Ohio Public Energy Council (NOPEC), making FES the generation supplier for approximately 425,000 customers in 160 Northeast Ohio communities represented by NOPEC. FES also extended its contracts with nine communities, including the City of Toledo, represented by the Northwest Ohio Aggregation Coalition (NOAC). Through these and other governmental aggregation contracts, including one with the City of Akron, FES provides competitive retail generation supply to approximately one million residential and small business customers in Ohio.

Consolidation of Transmission Assets into PJM *The Federal Energy Regulatory Commission approved our request to consolidate our ATSI transmission assets and operations into PJM Interconnection. This consolidation is expected to result in enhanced operational efficiency while providing customers of our Ohio utilities and Penn Power with better access to competitively priced generation.*

PJM

LE



Improving Energy Efficiency

Each of our utilities is committed to achieving energy-efficiency goals within its respective state service area. Toward that end, we're developing efficiency and demand reduction programs designed to help our customers better manage their energy use while delaying the need to build new power plants.

In 2009, our utilities in Ohio and Pennsylvania filed plans to comply with aggressive state mandates for energy efficiency and demand-side management. Our plans include home energy audits, an appliance turn-in program, direct load-control thermostats and, for our commercial and industrial customers, rebates for energy audits and energy-efficient lighting and motors.

In addition, we continue to participate in statewide programs in New Jersey that are part of its Energy Master Plan for energy efficiency and peak demand reductions. In one program, our Jersey Central Power & Light utility is using smart grid technologies and devices to achieve cost-effective reductions in non-critical customer load, such as air conditioning.

West Akron Campus LEED Certification *Our West Akron Campus earned Gold Level certification through the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) program for environmental design, construction and performance, making it one of the largest LEED-certified green office buildings in Ohio.*

Enhancing Our Environmental Performance

We continue to make significant progress in our efforts to enhance the environmental performance of our existing fleet.

In 2009, we neared completion of the Air Quality Compliance project at our Sammis Plant while announcing several new projects that should further reduce emission rates at our power plants. In addition, our merger with Allegheny Energy would more than double the amount of our supercritical coal capacity and renewable resources, which is expected to further reduce our exposure to changing environmental requirements.

To put this in perspective, high-efficiency, supercritical plants would comprise 68 percent of our total, combined coal-based generation, compared with the national average of 28 percent for all coal-fired generation. And, with Allegheny's pumped-storage and hydroelectric resources, we expect to have available more than 2,200 MW of renewable capacity upon completion of the merger.

Our renewable portfolio should continue to grow as we move forward with two major projects announced in 2009.

Beaver Valley License Extension *The Nuclear Regulatory Commission approved a 20-year license extension for Beaver Valley Units 1 and 2 in Shippingport, Pennsylvania, ensuring the plant will remain a source of safe, reliable and clean electricity for years to come. In addition, the Institute of Nuclear Power Operations recognized Beaver Valley as among the nation's top nuclear plants.*

At our Burger Plant, we plan to repower two units to generate electricity principally using renewable biomass as a fuel source. The retrofit is designed to significantly reduce sulfur dioxide, nitrogen oxides and mercury emissions at the plant. And, as more of the plant's biomass fuel is grown as an energy crop, it is expected to be carbon-neutral, removing as much carbon dioxide from the environment while the fuel source is growing as it releases when it is burned. When the retrofit is complete – currently scheduled for December 2012 – the Burger Plant is expected to be one of the largest biomass facilities in the United States.

We also acquired the rights to develop a compressed-air energy storage plant in Norton, Ohio. This resource would operate similar to our pumped-storage hydro facilities – storing energy at night for use during the day when it is needed. Energy storage is essential to enhancing the feasibility and cost-effectiveness of renewable energy such as wind and solar, which are intermittent resources that don't always produce power when electricity demand is high. We have made no development commitments, but if we move beyond current engineering work, the Norton Energy Storage project would be built in several phases – from nearly 270 MW to a total capacity of up to 2,700 MW.

Growing Your Investment in the Future

Your Company made steady progress in uncertain times, and I'm confident the steps we took in 2009 will help grow our business, and your investment, in the future.

I appreciate the dedicated efforts of our employees in helping us meet the difficult and unprecedented challenges of 2009. We'll continue to need their best efforts – including an unwavering commitment to working safely – to build on our progress in the years ahead.

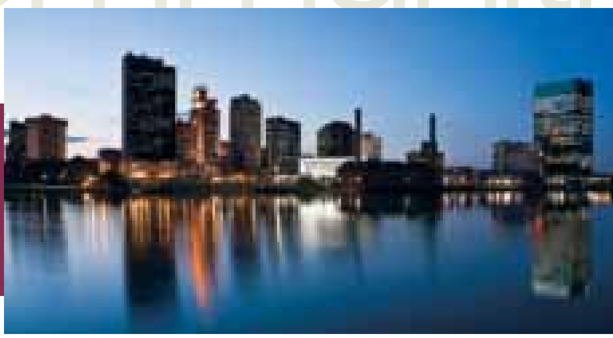
I look forward to the successful merger of FirstEnergy and Allegheny Energy and the expected benefits it will bring to shareholders, customers and employees. Thank you for your continued support as we work to grow FirstEnergy and achieve continued success.

Sincerely,

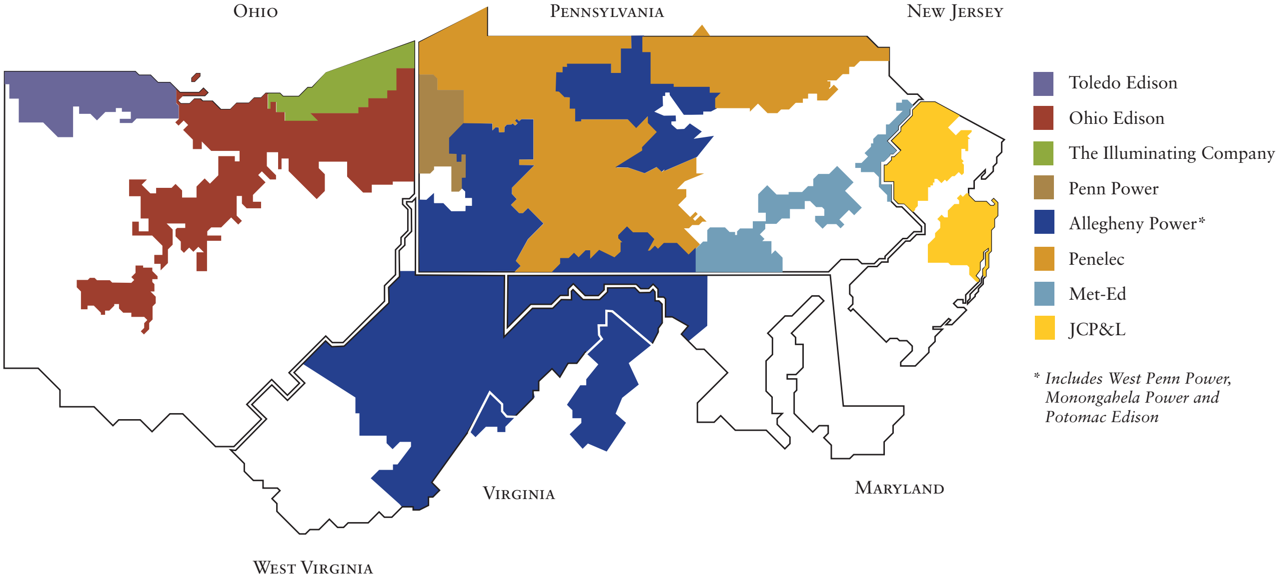
Anthony J. Alexander
President and Chief Executive Officer
March 22, 2010

Powering Our Communities

Powering Our Communities *FES introduced Powering Our Communities, an innovative program that provides economic support to communities in the Ohio Edison, The Illuminating Company and Toledo Edison service areas that purchase competitively priced, long-term electric generation supply from FES.*



COMBINING FirstEnergy AND Allegheny Energy



The combination of FirstEnergy and Allegheny Energy would create a leading regional energy provider with:

- Approximately $16 billion in annual revenues and $1.4 billion in annual net income (combined figures as of December 31, 2009).
- Ten regulated electric distribution companies providing electric service to more than six million customers in Pennsylvania, Ohio, Maryland, New Jersey, New York, Virginia and West Virginia.
- Nearly 20,000 miles of high-voltage transmission lines connecting the Midwest and Mid-Atlantic.
- Approximately 24,000 MW of generating capacity from a diversified mix of regional coal, nuclear, natural gas, oil, hydroelectric, contracted wind and pumped storage resources – including more than 2,200 MW of renewable energy.

Supercritical Coal

Expanding our Supercritical Coal Capacity *The combination of FirstEnergy and Allegheny Energy will more than double our supercritical coal capacity. FirstEnergy's Bruce Mansfield Plant is one of these highly efficient, clean-burning facilities.*

FirstEnergy Board of Directors

Paul T. Addison
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (Citigroup).

Anthony J. Alexander
President and Chief Executive Officer of FirstEnergy Corp.

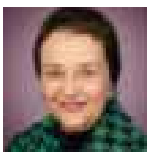
Michael J. Anderson
Chairman of the Board, President and Chief Executive Officer of The Andersons, Inc.

Dr. Carol A. Cartwright
President of Bowling Green State University. Retired President of Kent State University.

William T. Cottle
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company.

Robert B. Heisler, Jr.
Dean of the College of Business Administration and Graduate School of Management of Kent State University. Retired Chairman of the Board of KeyBank N.A.

Ernest J. Novak, Jr.
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP.



Catherine A. Rein
Retired, formerly Senior Executive Vice President and Chief Administrative Officer of MetLife, Inc.

George M. Smart
Non-executive Chairman of the FirstEnergy Corp. Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc.

Wes M. Taylor
Retired, formerly President of TXU Generation.

Jesse T. Williams, Sr.
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company.

Dear Shareholders:

FirstEnergy management and employees made significant progress in 2009 despite the economic challenges facing our nation and our Company. On behalf of your Board of Directors, I congratulate them for another successful year.

As FirstEnergy executes its strategy for long-term success, the Board continues to support your management team as it focuses on important areas such as safety, financial and risk management, operations, and regulatory and legislative matters. We also remain committed to ensuring that we have the appropriate corporate governance practices and policies in place.

With operational and financial strength on its side, FirstEnergy is well positioned to take advantage of opportunities that lie ahead, including its proposed merger with Allegheny Energy, which is expected to create sustainable value to shareholders.

Given our confidence in the Company's prospects, your Board maintained the annual dividend rate of $2.20 per share in 2009. And, we will continue to review the dividend on a quarterly basis as FirstEnergy moves to complete the transition to competitive markets and attain the anticipated benefits from the merger with Allegheny Energy.

Your Board remains dedicated to enhancing the value of your investment in FirstEnergy, and looks forward to your continued trust and support.

Sincerely,

George M Smart

George M. Smart, *Chairman of the Board*

FirstEnergy Corp. Officers

Anthony J. Alexander
President and Chief Executive Officer

Mark T. Clark
Executive Vice President and Chief Financial Officer

Richard R. Grigg
Executive Vice President and President, FirstEnergy Utilities

Gary R. Leidich
Executive Vice President and President, FirstEnergy Generation

Leila L. Vespoli
Executive Vice President and General Counsel

James F. Pearson
Vice President and Treasurer

Harvey L. Wagner
Vice President, Controller and Chief Accounting Officer

Rhonda S. Ferguson
Corporate Secretary

Kevin R. Burgess
Assistant Controller

Jacqueline S. Cooper
Assistant Corporate Secretary

Dena R. McKee
Assistant Controller

Kelley E. Mendenhall
Assistant Treasurer

Randy Scilla
Assistant Treasurer

Edward J. Udovich
Assistant Corporate Secretary

Lisa S. Wilson
Assistant Controller

2009 GAAP to Non-GAAP* Reconciliation

Basic Earnings Per Share (GAAP)	**$3.31**
Excluding Special Items:	
Regulatory Charges	0.55
Power Contract Mark-to-Market Adjustment	0.42
Debt Redemption Premiums	0.31
Organizational Restructuring/Incremental Strike Costs	0.14
Trust Securities Impairment	0.09
Income Tax Issue Resolution	(0.53)
Non-Core Asset Sales/Impairments	(0.52)
Basic Earnings Per Share (Non-GAAP)	**$3.77**

*This report contains non-GAAP financial measures. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). These non-GAAP financial measures are intended to complement, and not considered as an alternative, to the most directly comparable GAAP financial measure. Also, the non-GAAP financial measures may not be comparable to similarly titled measures used by other entities.

INFORMATION CONCERNING FORWARD-LOOKING STATEMENTS

In addition to historical information, this annual report may contain a number of “forward-looking statements” as defined in the Private Securities Litigation Reform Act of 1995. Words such as anticipate, expect, project, intend, plan, believe, and words and terms of similar substance used in connection with any discussion of future plans, actions, or events identify forward-looking statements. Forward-looking statements relating to the proposed merger include, but are not limited to: statements about the benefits of the proposed merger involving FirstEnergy and Allegheny, including future financial and operating results; FirstEnergy’s and Allegheny’s plans, objectives, expectations and intentions; the expected timing of completion of the transaction; and other statements relating to the merger that are not historical facts. Forward-looking statements involve estimates, expectations and projections and, as a result, are subject to risks and uncertainties. There can be no assurance that actual results will not materially differ from expectations. Important factors could cause actual results to differ materially from those indicated by such forward-looking statements. With respect to the proposed merger, these factors include, but are not limited to: risks and uncertainties relating to the ability to obtain the requisite FirstEnergy and Allegheny shareholder approvals; the risk that FirstEnergy or Allegheny may be unable to obtain governmental and regulatory approvals required for the merger, or required governmental and regulatory approvals may delay the merger or result in the imposition of conditions that could reduce the anticipated benefits from the merger or cause the parties to abandon the merger; the risk that a condition to closing of the merger may not be satisfied; the length of time necessary to consummate the proposed merger; the risk that the businesses will not be integrated successfully; the risk that the cost savings and any other synergies from the transaction may not be fully realized or may take longer to realize than expected; disruption from the transaction making it more difficult to maintain relationships with customers, employees or suppliers; the diversion of management time on merger-related issues; the effect of future regulatory or legislative actions on the companies; and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect. These risks, as well as other risks associated with the merger, are more fully discussed in the preliminary joint proxy statement/prospectus that is included in the Registration Statement on Form S-4 that was filed by FirstEnergy with the SEC in connection with the merger. Additional risks and uncertainties are identified and discussed in FirstEnergy’s and Allegheny’s reports filed with the SEC and available at the SEC’s website at www.sec.gov. Forward-looking statements included in this annual report speak only as of the date of this annual report. Neither FirstEnergy nor Allegheny undertakes any obligation to update its forward-looking statements to reflect events or circumstances after the date of this annual report.

ADDITIONAL INFORMATION AND WHERE TO FIND IT

In connection with the proposed merger, FirstEnergy filed a Registration Statement on Form S-4 with the SEC that includes a preliminary joint proxy statement of FirstEnergy and Allegheny and that also constitutes a preliminary prospectus of FirstEnergy. FirstEnergy and Allegheny will mail the definitive joint proxy statement/prospectus to their respective shareholders. **FirstEnergy and Allegheny urge investors and shareholders to read the definitive joint proxy statement/prospectus regarding the proposed merger when it becomes available, as well as other documents filed with the SEC, because they will contain important information.** You may obtain copies of all documents filed with the SEC regarding this proposed transaction, free of charge, at the SEC’s website (www.sec.gov). You may also obtain these documents, free of charge, from FirstEnergy’s website (www.firstenergycorp.com) under the tab “Investors” and then under the heading “Financial Information” and then under the item “SEC Filings.” You may also obtain these documents, free of charge, from Allegheny’s website (www.alleghenyenergy.com) under the tab “Investors” and then under the heading “SEC Filings.”

PARTICIPANTS IN THE MERGER SOLICITATION

FirstEnergy, Allegheny and their respective directors, executive officers and certain other members of management and employees may be soliciting proxies from FirstEnergy and Allegheny shareholders in favor of the merger and related matters. Information regarding the persons who may, under the rules of the SEC, be deemed participants in the solicitation of FirstEnergy and Allegheny shareholders in connection with the proposed merger is set forth in the preliminary joint proxy statement/prospectus contained in the above-referenced Registration Statement on Form S-4. You can find information about FirstEnergy’s executive officers and directors in its definitive proxy statement filed with the SEC in connection with its 2010 Annual Meeting of Shareholders and in its Annual Report on the Form 10-K filed with the SEC on February 19, 2010. You can find information about Allegheny’s executive officers and directors in its definitive proxy statement filed with the SEC in connection with its 2010 Annual Meeting of Stockholders and in its Annual Report on the Form 10-K filed with the SEC on March 1, 2010. Additional information about FirstEnergy’s executive officers and directors and Allegheny’s executive officers and directors can be found in the above-referenced Registration Statement on Form S-4. You can obtain free copies of these documents from FirstEnergy and Allegheny using the website information above.

ANNUAL REPORT 2009

Contents	Page

GLOSSARY OF TERMS

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

ATSI	American Transmission Systems, Incorporated, owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial and other corporate support services
FEV	FirstEnergy Ventures Corp., invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	Met-Ed, Penelec and Penn
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shelf Registrants	FirstEnergy, OE, CEI, TE, JCP&L, Met-Ed and Penelec
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FirstEnergy Ventures Corp. and Boich Companies, that owns mining and coal transportation operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Waverly	The Waverly Power and Light Company, a wholly owned subsidiary of Penelec

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

AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP-Ohio	American Municipal Power-Ohio, Inc.
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CBP	Competitive Bid Process
CMEC	Capacity market Evolution Committee
CO_2	Carbon dioxide
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DCPD	Deferred Compensation Plan for Outside Directors
DPA	Department of the Public Advocate, Division of Rate Counsel (New Jersey)
ECAR	East Central Area Reliability Coordination Agreement
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency

GLOSSARY OF TERMS, Cont'd.

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
IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
IRS	Internal Revenue Service
JCARR	Joint Committee on Agency Review
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-emitting Diode
LIBOR	London Interbank Offered Rate
LOC	Letter of Credit
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MW	Megawatts
MWH	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NNSR	Non-Attainment New Source Review
NOPEC	Northeast Ohio Public Energy Council
NOV	Notice of Violation
NO_X	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
QSPE	Qualifying Special-Purpose Entity
RCP	Rate Certainty Plan
RECs	Renewable Energy Credits
RFP	Request for Proposal
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SB221	Amended Substitute Senate Bill 221

SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRECs	Solar Renewable Energy Credits
TBC	Transition Bond Charge
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VERO	Voluntary Enhanced Retirement Option
VIE	Variable Interest Entity

FIRSTENERGY CORP.

SELECTED FINANCIAL DATA

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

(1) Dividends declared in 2009 and 2008 include four quarterly dividends of $0.55 per share. Dividends declared in 2007 include three quarterly payments of $0.50 per share in 2007 and one quarterly payment of $0.55 per share in 2008. Dividends declared in 2006 include three quarterly payments of $0.45 per share in 2006 and one quarterly payment of $0.50 per share in 2007. Dividends declared in 2005 include two quarterly payments of $0.4125 per share in 2005, one quarterly payment of $0.43 per share in 2005 and one quarterly payment of $0.45 per share in 2006.

PRICE RANGE OF COMMON STOCK

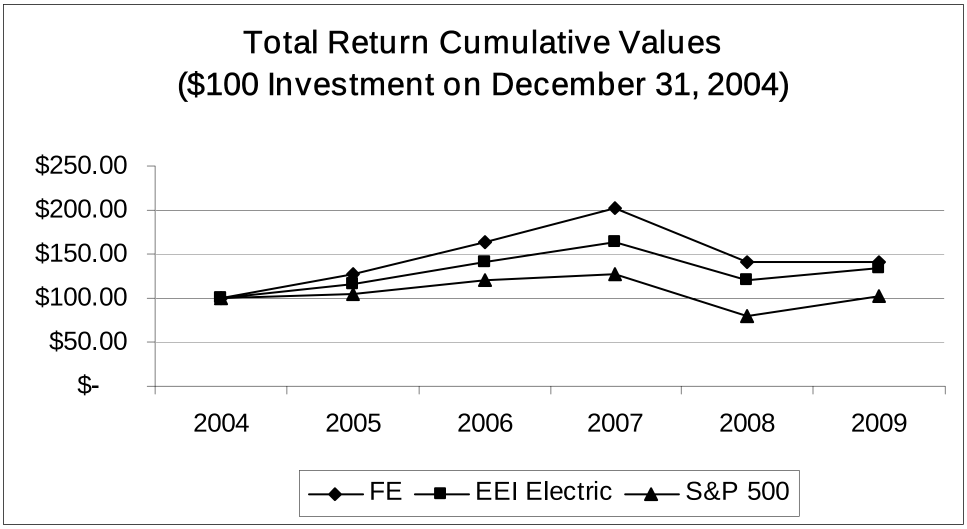
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

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

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2004 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 110,712 and 110,365 holders of 304,835,407 shares of FirstEnergy's common stock as of December 31, 2009 and January 31, 2010, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12 to the consolidated financial statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

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

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

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Pennsylvania.
- The impact of the regulatory process on the pending matters in Ohio, Pennsylvania and New Jersey.
- Business and regulatory impacts from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins.
- Changes in markets for energy services.
- Changing energy and commodity market prices and availability.
- Replacement power costs being higher than anticipated or inadequately hedged.
- The continued ability of FirstEnergy's regulated utilities to collect transition and other charges or to recover increased transmission costs.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission regulations.
- The potential impacts of the U.S. Court of Appeals' July 11, 2008 decision requiring revisions to the CAIR rules and the scope of any laws, rules or regulations that may ultimately take their place.
- The uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the Air Quality Compliance Plan (including that such amounts could be higher than anticipated or that certain generating units may need to be shut down) or levels of emission reductions related to the Consent Decree resolving the NSR litigation or other potential similar regulatory initiatives or actions.
- Adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC.
- Ultimate resolution of Met-Ed's and Penelec's TSC filings with the PPUC.
- The continuing availability of generating units and their ability to operate at or near full capacity.
- The ability to comply with applicable state and federal reliability standards and energy efficiency mandates.
- The ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives).
- The ability to improve electric commodity margins and to experience growth in the distribution business.
- The changing market conditions that could affect the value of assets held in the registrants' nuclear decommissioning trusts, pension trusts and other trust funds, and cause FirstEnergy to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The ability to access the public securities and other capital and credit markets in accordance with FirstEnergy's financing plan and the cost of such capital.
- Changes in general economic conditions affecting the registrants.
- The state of the capital and credit markets affecting the registrants.
- Interest rates and any actions taken by credit rating agencies that could negatively affect the registrants' access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- The continuing decline of the national and regional economy and its impact on the registrants' major industrial and commercial customers.
- Issues concerning the soundness of financial institutions and counterparties with which the registrants do business.
- The expected timing and likelihood of completion of the proposed merger with Allegheny Energy, Inc., including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, the ability to maintain relationships with customers, employees or suppliers as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.
- The risks and other factors discussed from time to time in the registrants' SEC filings, and other similar factors.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrants' business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. A security rating is not a recommendation to buy, sell or hold securities that may be subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating. The registrants expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events or otherwise.

EXECUTIVE SUMMARY

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

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

Financial Matters

Proposed Merger with Allegheny Energy, Inc.

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

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

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

Financing Activities

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

Rating Agency Actions

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

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

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

Sumpter Plant Sale

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

OVEC Participation Interest Sale

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

Legacy Power Contracts

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

Operational Matters

Recessionary Market Conditions and Weather Impacts

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

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

FirstEnergy Reorganization and Voluntary Enhanced Retirement Option

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

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

PJM Regional Transmission Organization (RTO) Integration

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

Beaver Valley Power Station License Renewal

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

Refueling Outages

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

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

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

R. E. Burger Plant

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

Fremont Energy Center

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

Norton Energy Storage Project

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

Labor Agreements

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

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

Smart Grid Proposal

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

Powering our Communities Program

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

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

Regulatory Matters - Ohio

Ohio Regulatory Update

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

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

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

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

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

Regulatory Matters - Pennsylvania

NUG Statement Compliance Filing

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

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

Act 129

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

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

Transmission Cost Recovery

In 2008, the PPUC approved the Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. The TSCs included a component for under-recovery of actual transmission costs incurred during the prior period (Met-Ed - $144 million and Penelec - $4 million) and transmission cost projections for June 2008 through May 2009 (Met-Ed - $258 million and Penelec - $92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through future TSCs by December 31, 2010. Various intervenors filed complaints against those filings and the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while allowing Met-Ed to implement the June 1, 2008 rider, subject to refund. In August 2009, the ALJ issued a Recommend Decision to the PPUC approving Met-Ed's and Penelec's TSCs as filed and dismissing all complaints. On January 28, 2010, the PPUC adopted a motion which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, and instructs Met-Ed and Penelec to work with the parties and file a petition to retain any over-collection, with interest, until 2011 for the purpose of providing mitigation of future rate increases starting in 2011 for their customers. The Companies are now awaiting an order, which is expected to be consistent with the motion. If so, Met-Ed and Penelec plan to appeal such a decision to the Commonwealth Court of Pennsylvania. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of the Companies that they should prevail in any such appeal and therefore expect to fully recover the approximately $170.5 million ($138.7 million for Met-Ed and $31.8 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

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

Default Service Plan

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

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

Regulatory Matters – New Jersey

Solar Renewable Energy Proposal

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

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

FIRSTENERGY'S BUSINESS

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

- Energy Delivery Services transmits and distributes electricity through our eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its PLR and default service requirements in Ohio, Pennsylvania and New Jersey. Its revenues are primarily derived from the delivery of electricity within our service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Ohio, Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES and from non-affiliated power suppliers, the net PJM and MISO transmission expenses related to the delivery of the respective generation loads, and the deferral and amortization of certain fuel costs.

The service areas of our utilities are summarized below:

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

- Competitive Energy Services supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the PLR and default service requirements of our Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns or leases and operates 19 generating facilities with a net demonstrated capacity of 13,710 MWs and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from affiliated and non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment's customers.

PROPOSED MERGER WITH ALLEGHENY

Proposed Merger with Allegheny Energy, Inc.

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

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

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

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

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

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

STRATEGY AND OUTLOOK

We continue to focus on the primary objectives we have developed that support our business fundamentals – safety, generation, reliability, transitioning to competitive markets, managing our liquidity, and growing earnings. To achieve these objectives, we are pursuing the following strategies:

- strengthening our safety focus;
- maximizing the utilization of our generating fleet;
- meeting our transmission and distribution reliability goals;
- managing the transition to competitive generation market prices in Ohio and Pennsylvania;
- executing our direct-to-customer retail sales strategy;
- maintaining adequate and ready access to cash resources; and
- achieving our financial goals and commitments to shareholders.

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

We began implementation of our long-term strategic plans during the past several years. Our gradual progression to competitive generation markets across our tri-state service territory and other strategies to improve performance and deliver consistent financial results is characterized by several important transition periods:

2007 and 2008

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

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

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

In mid-2008, we also entered into a joint venture to acquire a majority stake in the Signal Peak coal mining project. As part of that transaction, we also entered into a 15-year agreement to purchase up to 10 million tons of coal annually from the mine, securing a long-term western fuel supply at attractive prices. The higher Btu content of Signal Peak coal versus Powder River Basin coal is expected to help avoid fossil plant derates of approximately 170 MW and help support our incremental generation expansion plans. The burning of Signal Peak coal is also expected to improve the performance of some of our older generating units, which will factor into our decision making process regarding potential future plant shutdowns. Signal Peak began commercial operation in December 2009. Although, we have experienced some issues with the start-up of commercial operations, we believe those issues will be resolved and Signal Peak is expected to achieve its production goals for the year. In the fourth quarter of 2008, FES assigned two existing Powder River Basin contracts to a third party in order to reduce its forecasted 2010 long coal position as a result of expected deliveries from Signal Peak.

In July 2008, we filed both a comprehensive ESP and MRO with the PUCO. In November 2008, the PUCO issued an order denying the MRO. In December 2008, the PUCO approved, but substantially modified, our ESP. After determining that the plan no longer maintained a reasonable balance between providing customers with continued rate stability and a fair return on the Ohio Companies' investments to serve customers, we withdrew our application for the ESP as allowed by law (see Regulatory Matters – Ohio).

2009 and 2010

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

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

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

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

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

As we look to 2010 and beyond, we expect to continue our focus on operational excellence with an emphasis on continuous improvement in our core businesses to position for success during the next phase of the market recovery. This includes ongoing incremental investment in projects to increase our generation capacity and energy production capability as well as programs to continue to improve transmission and distribution system reliability and customer service.

2011 and Beyond

Another major transition period for FirstEnergy will begin in 2011 as the current cap on Met-Ed's and Penelec's retail generation rates is expected to expire. Beginning in 2011, Met-Ed and Penelec have approval from the PPUC to obtain their power supply from the competitive wholesale market and fully recover their generation costs through retail rates. As a result, FES plans to redeploy the power currently sold to Met-Ed and Penelec primarily to retail customers located in and near our generation footprint and into local regional auctions and RFPs for PLR service, with the remainder available for sale in the wholesale market.

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

We will continue our efforts to extract additional production capability from existing generating plants as discussed under "Capital Expenditures Outlook" below and maintain the financial and strategic flexibility necessary to thrive in the competitive marketplace.

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

Financial Outlook

In response to the unprecedented volatility in the capital and credit markets that began in late 2008 and our increased risk exposure to the commodity markets that resulted from the outcome of the Ohio CBP, we carefully assessed our exposure to counterparty credit risk, our access to funds in the capital and credit markets, and market-related changes in the value of our postretirement benefit trusts, nuclear decommissioning trusts and other investments. We have taken steps to strengthen our liquidity position and provide additional flexibility to meet our anticipated obligations and those of our subsidiaries.

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

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

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

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

Positive earnings drivers in 2010 are expected to include:

- Increased FES commodity margin from implementation of the retail strategy and the restructuring of the PJM PLR contracts;

- Increased distribution revenues from projected sales of 110 million MWH in 2010 vs. 102 million MWH in 2009, and a full year of both the distribution rate increase and Delivery Service Improvement Rider in Ohio;

- A full year of operation and maintenance cost savings that resulted from 2009 staffing adjustments, changes in our compensation structure, fossil plant outage schedule changes and general cost-saving measures; and

- Reduced costs from one less nuclear refueling outage in 2010 vs. 2009.

Negative earnings drivers in 2010 are expected to include:

- Reduced gains from sale of nuclear decommissioning trust investments in 2009;

- Reduced RTC margin for CEI:

- The absence of significant favorable tax settlements in 2010 compared to 2009; and

- Increased benefit and financing costs, general taxes and depreciation expense.

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

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

Positive earnings drivers for 2011 could include:

- The December 31, 2010 expiration of FES' contracts to serve Met-Ed and Penelec's generation requirements. In 2011, 100% of the generation output at FES will be priced at market;

- Potentially increased distribution deliveries tied to an economic recovery; and

- Incremental Signal Peak coal production and price improvement

Negative earnings drivers for 2011 could include:

- Increased nuclear fuel costs and coal contract pricing adjustments;

- Pressure to maintain O&M cost reductions vs. 2010 with a potentially improving economy

- Increased depreciation and general taxes and lower capitalized interest resulting from completion of our Sammis AQC and Fremont construction projects

Capital Expenditures Outlook

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

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

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

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

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

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

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

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

Environmental Outlook

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

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

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

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

To further enhance our environmental performance, we have implemented our AQC plan. The plan includes projects designed to ensure that all of the facilities in our generation fleet are operated in compliance with all applicable emissions standards and limits, including NOx SO2 and particulate. It also fulfills the requirements imposed by the 2005 Sammis Consent Decree that resolved Sammis NSR litigation. At the end of 2010, we will have invested approximately $1.8 billion at our W.H. Sammis Plant in Stratton, Ohio, to further reduce emissions of SO2 and NOx. This multi-year environmental retrofit project, which began in 2006 and is expected to be completed in 2010, is designed to reduce the plant's SO2 emissions by 95% and NOx by at least 64%. This is one of the largest environmental retrofit projects in the nation.

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

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

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

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

- Bringing online 132.5 MW of wind generation in 2009 and we now sell over 1 million MWh per year of wind generation.

- Testing of CO2 sequestration at our R.E. Burger Plant. The results of this testing will help us gain a better understanding of the potential for geological storage of CO2.

- Supporting afforestation – growing forests on non-forested land – and other efforts designed to remove CO2 from the environment.

- Participating in the U.S. EPA's SF6 (sulfur hexafluoride) Emissions Reduction Partnership for Electric Power Systems since its inception in 1998. Since then, we have reduced emissions of SF6 by nearly 20 metric tons, resulting in an equivalent reduction of nearly 430,000 tons of CO2.

- Supporting research to develop and evaluate cost effective sorbent materials for CO2 capture including work by Powerspan at the Burger Plant and the University of Akron.

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

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

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

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

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

Achieving Our Vision

Our success in these and other key areas will help us continue to achieve our vision of being a leading regional energy provider, recognized for operational excellence, outstanding customer service and our commitment to safety; the choice for long-term growth, investment value and financial strength; and a company driven by the leadership, skills, diversity and character of our employees.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges, including:

- risks arising from the reliability of our power plants and transmission and distribution equipment;
- changes in commodity prices could adversely affect our profit margins;
- we are exposed to operational, price and credit risks associated with selling and marketing products in the power markets that we do not always completely hedge against;
- the use of derivative contracts by us to mitigate risks could result in financial losses that may negatively impact our financial results;
- our risk management policies relating to energy and fuel prices, and counterparty credit, are by their very nature risk related and we could suffer economic losses despite such policies;
- nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- capital market performance and other changes may decrease the value of decommissioning trust fund, pension fund assets and other trust funds which then could require significant additional funding;
- we could be subject to higher costs and/or penalties related to mandatory reliability standards set by NERC/FERC or changes in the rules of organized markets and the states in which we do business;
- we rely on transmission and distribution assets that we do not own or control to deliver our wholesale electricity. If transmission is disrupted, including our own transmission, or not operated efficiently, or if capacity is inadequate, our ability to sell and deliver power may be hindered;
- disruptions in our fuel supplies could occur, which could adversely affect our ability to operate our generation facilities and impact financial results;
- temperature variations as well as weather conditions or other natural disasters could have a negative impact on our results of operations and demand significantly below or above our forecasts could adversely affect our energy margins;
- we are subject to financial performance risks related to regional and general economic cycles and also related to heavy manufacturing industries such as automotive and steel;
- increases in customer electric rates and the impact of the economic downturn may lead to a greater amount of uncollectible customer accounts;
- the goodwill of one or more of our operating subsidiaries may become impaired, which would result in write-offs of the impaired amounts;

- we face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;

- significant increases in our operation and maintenance expenses, including our health care and pension costs, could adversely affect our future earnings and liquidity;

- our business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to our reputation and/or results of operations;

- acts of war or terrorism could negatively impact our business;

- capital improvements and construction projects may not be completed within forecasted budget, schedule or scope parameters;

- changes in technology may significantly affect our generation business by making our generating facilities less competitive;

- we may acquire assets that could present unanticipated issues for our business in the future, which could adversely affect our ability to realize anticipated benefits of those acquisitions;

- ability of certain FirstEnergy companies to meet their obligations to other FirstEnergy companies;

- ability to obtain the approvals required to complete our merger with Allegheny or, in order to do so, the combined company may be required to comply with material restrictions or conditions;

- if completed, our merger with Allegheny may not achieve its intended results;

- we will be subject to business uncertainties and contractual restrictions while the merger with Allegheny is pending that could adversely affect our financial results;

- failure to complete the merger with Allegheny could negatively impact our stock price and our future business and financial results;

- complex and changing government regulations could have a negative impact on our results of operations;

- regulatory changes in the electric industry, including a reversal, discontinuance or delay of the present trend toward competitive markets, could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;

- the prospect of rising rates could prompt legislative or regulatory action to restrict or control such rate increases; this in turn could create uncertainty affecting planning, costs and results of operations and may adversely affect the utilities' ability to recover their costs, maintain adequate liquidity and address capital requirements;

- our profitability is impacted by our affiliated companies' continued authorization to sell power at market-based rates;

- there are uncertainties relating to our participation in regional transmission organizations;

- a significant delay in or challenges to various elements of ATSI's consolidation into PJM, including but not limited to, the intervention of parties to the regulatory proceedings, could have a negative impact on our results of operations and financial condition;

- energy conservation and energy price increases could negatively impact our financial results;

- the EPA is conducting NSR investigations at a number of our generating plants, the results of which could negatively impact our results of operations and financial condition;

- our business and activities are subject to extensive environmental requirements and could be adversely affected by such requirements;

- costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws, including limitations on GHG emissions could adversely affect cash flow and profitability;

- the physical risks associated with climate change may impact our results of operations and cash flows;
- remediation of environmental contamination at current or formerly owned facilities;
- availability and cost of emission credits could materially impact our costs of operations;
- mandatory renewable portfolio requirements could negatively affect our costs;
- we are and may become subject to legal claims arising from the presence of asbestos or other regulated substances at some of our facilities;
- the continuing availability and operation of generating units is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;
- future changes in financial accounting standards may affect our reported financial results;
- increases in taxes and fees;
- interest rates and/or a credit rating downgrade could negatively affect our financing costs, our ability to access capital and our requirement to post collateral;
- we must rely on cash from our subsidiaries and any restrictions on our utility subsidiaries' ability to pay dividends or make cash payments to us may adversely affect our financial condition;
- we cannot assure common shareholders that future dividend payments will be made, or if made, in what amounts they may be paid;
- disruptions in the capital and credit markets may adversely affect our business, including the availability and cost of short-term funds for liquidity requirements, our ability to meet long-term commitments, our ability to effectively hedge our generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect our results of operations, cash flows and financial condition; and
- questions regarding the soundness of financial institutions or counterparties could adversely affect us.

RESULTS OF OPERATIONS

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

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

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

Summary of Results of Operations – 2009 Compared with 2008

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

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

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

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

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

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

Energy Delivery Services – 2009 Compared to 2008

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

Revenues –

The decrease in total revenues resulted from the following sources:

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

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

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

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

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

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

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

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

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

Expenses –

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other Expense –

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

Competitive Energy Services – 2009 Compared to 2008

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

Revenues –

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

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

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

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

The lower affiliated company wholesale generation revenues of $125 million were due to lower sales volumes to the Ohio Companies combined with lower unit prices to the Pennsylvania companies, partially offset by higher unit prices to the Ohio Companies and increased sales volumes to the Pennsylvania Companies. The lower sales volumes and higher unit prices to the Ohio Companies reflected the results of the power procurement processes in the first half of 2009 (see Regulatory Matters – Ohio). The higher sales to the Pennsylvania Companies were due to increased Met-Ed and Penelec generation sales requirements supplied by FES partially offset by lower sales to Penn due to decreased default service requirements in 2009 compared to 2008. Additionally, while unit prices for each of the Pennsylvania Companies did not change, the mix of sales among the companies caused the overall price to decline.

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

Source of Change in Non-Affiliated Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 8.6 % increase in sales volumes	$ 53
Change in prices	110
	163
Wholesale:	
Effect of 13.9 % decrease in sales volumes	(100)
Change in prices	51
	(49)
Net Increase in Non-Affiliated Generation Revenues	$ 114

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

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

Expenses -

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

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

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

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

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

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

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

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

Other Income (Expense) –

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

Other – 2009 Compared to 2008

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

Summary of Results of Operations – 2008 Compared with 2007

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

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

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

Energy Delivery Services – 2008 Compared to 2007

Net income decreased $49 million to $916 million in 2008 compared to $965 million in 2007, primarily due to increased purchased power costs, decreased deferral of new regulatory assets and lower investment income, partially offset by higher revenues.

Revenues –

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	2008	2007	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,882	$ 3,909	$ (27)
Generation sales:			
Retail	5,768	5,393	375
Wholesale	962	694	268
Total generation sales	6,730	6,087	643
Transmission	1,267	1,118	149
Other	189	208	(19)
Total Revenues	$ 12,068	$ 11,322	$ 746

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

Electric Distribution KWH Deliveries	
Residential	(0.9)%
Commercial	(0.9)%
Industrial	(3.9)%
Total Distribution KWH Deliveries	(1.9)%

The decrease in electric distribution deliveries to residential and commercial customers was primarily due to reduced summer usage resulting from milder weather in 2008 compared to the same period of 2007, as cooling degree days decreased by 14.6%; heating degree days increased by 2.5%. In the industrial sector, a decrease in deliveries to automotive customers (18%) and steel customers (4%) was partially offset by an increase in usage by refining customers (3%).

The following table summarizes the price and volume factors contributing to the $643 million increase in generation revenues in 2008 compared to 2007:

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

The decrease in retail generation sales volumes was primarily due to milder weather and economic conditions in the Utilities' service territories and an increase in customer shopping for Penn, Penelec and JCP&L. The increase in retail generation prices in 2008 was due to higher generation rates for JCP&L resulting from the New Jersey BGS auctions effective June 1, 2007 and June 1, 2008, and the Ohio Companies' fuel cost recovery riders that became effective in January 2008. The increase in wholesale prices reflected higher spot market prices for PJM market participants.

Transmission revenues increased $149 million due to higher transmission rates for Met-Ed and Penelec resulting from the annual update to their TSC riders in mid-2008 and the Ohio Companies' PUCO-approved transmission tariff increases that became effective July 1, 2007 and July 1, 2008. The difference between transmission revenues accrued and transmission expenses incurred is deferred, resulting in no material impact to current period earnings.

Expenses –

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

- Purchased power costs were $507 million higher in 2008 due to higher unit costs and a decrease in the amount of NUG costs deferred. The increase in unit costs from non-affiliates was primarily due to higher costs for JCP&L resulting from the BGS auction process. JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. Higher unit costs from FES reflect the increases in the Ohio Companies' retail generation rates, as provided for under the PSA then in effect with FES. The decrease in purchase volumes was due to the lower retail generation sales requirements described above.

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

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

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

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

  - a $15 million decrease for contractor costs associated with vegetation management activities, as more of that work performed in 2008 related to capital projects;

  - a $13 million decrease in uncollectible expense due primarily to the recognition of higher uncollectible reserves in 2007 and enhanced collection processes in 2008;

  - lower labor costs charged to operating expense of $12 million, as a greater proportion of labor was devoted to capital-related projects in 2008; and

  - a $6 million decline in regulatory program costs, including customer rebates.

- Amortization of regulatory assets increased $34 million due primarily to higher transition cost amortization for the Ohio Companies, partially offset by decreases at JCP&L for regulatory assets that were fully recovered at the end of 2007 and in the first half of 2008.

- The deferral of new regulatory assets during 2008 was $208 million lower than in 2007. MISO transmission deferrals and RCP fuel deferrals decreased $166 million, as more transmission and generation costs were recovered from customers through PUCO-approved riders. Also contributing to the decrease was the absence of the one-time deferral in 2007 of decommissioning costs related to the Saxton nuclear research facility ($27 million) and lower PJM transmission cost deferrals ($32 million), partially offset by increased societal benefit deferrals ($15 million).

- Higher depreciation expense of $13 million resulted from additional capital projects placed in service since 2007.

- General taxes increased $19 million due to higher gross receipts taxes, property taxes and payroll taxes.

Other Expense –

Other expense increased $32 million in 2008 compared to 2007 due to lower investment income of $70 million, resulting primarily from the repayment of notes receivable from affiliates, partially offset by lower interest expense (net of capitalized interest) of $38 million. The interest expense declined for the Ohio Companies due to their redemption of certain pollution control notes in the second half of 2007.

Competitive Energy Services – 2008 Compared to 2007

Net income for this segment was $472 million in 2008 compared to $495 million in 2007. The $23 million reduction in net income reflects a decrease in gross generation margin (revenue less fuel and purchased power) and higher depreciation expense, which were partially offset by lower other operating expenses.

Revenues –

Total revenues increased $170 million in 2008 compared to 2007. This increase primarily resulted from higher unit prices on affiliated generation sales to the Ohio Companies and increased non-affiliated wholesale sales, partially offset by lower retail sales.

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

Revenues by Type of Service	2008	2007	Increase (Decrease)
		(In millions)	
Non-Affiliated Generation Sales:			
Retail	$ 615	$ 712	$ (97)
Wholesale	717	603	114
Total Non-Affiliated Generation Sales	1,332	1,315	17
Affiliated Generation Sales	2,968	2,901	67
Transmission	150	103	47
Other	89	50	39
Total Revenues	$ 4,539	$ 4,369	$ 170

The lower retail revenues reflect reduced commercial and industrial contract renewals in the PJM market and the termination of certain government aggregation programs in MISO. Higher non-affiliated wholesale revenues resulted from higher capacity prices and increased sales volumes in PJM, partially offset by decreased sales volumes in MISO.

The increased affiliated company generation revenues were due to higher unit prices for the Ohio Companies partially offset by lower unit prices for the Pennsylvania Companies and decreased affiliated sales volumes. The higher unit prices reflected fuel-related increases in the Ohio Companies' retail generation rates. While unit prices for each of the Pennsylvania Companies did not change, the mix of sales among the companies caused the overall price to decline. The reduction in PSA sales volumes to the Ohio and Pennsylvania Companies was due to the milder weather and industrial sales changes discussed above and reduced default service requirements in Penn's service territory as a result of its RFP process.

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

Source of Change in Non-Affiliated Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 15.8% decrease in sales volumes	$ (113)
Change in prices	16
	(97)
Wholesale:	
Effect of 3.8% increase in sales volumes	23
Change in prices	91
	114
Net Increase in Non-Affiliated Generation Revenues	$ 17

Source of Change in Affiliated Generation Revenues	Increase (Decrease)
	(In millions)
Ohio Companies:	
Effect of 1.5% decrease in sales volumes	$ (34)
Change in prices	129
	95
Pennsylvania Companies:	
Effect of 1.5% decrease in sales volumes	(10)
Change in prices	(18)
	(28)
Net Increase in Affiliated Generation Revenues	$ 67

Transmission revenues increased $47 million due primarily to higher transmission rates in MISO and PJM.

Expenses –

Total expenses increased $203 million in 2008 due to the following factors:

- Fossil fuel costs increased $155 million due to higher unit prices ($163 million) partially offset by lower generation volume ($8 million). The increased unit prices primarily reflect increased rates for existing eastern coal contracts, higher transportation surcharges and emission allowance costs in 2008. Nuclear fuel expense was $10 million higher as nuclear generation increased in 2008.

- Purchased power costs increased $15 million due primarily to higher spot market and capacity prices, partially offset by reduced volume requirements.

- Fossil operating costs decreased $22 million due to a gain on the sale of a coal contract in the fourth quarter of 2008 ($20 million), reduced scheduled outage activity ($17 million) and increased gains from emission allowance sales ($7 million), partially offset by costs associated with a cancelled electro-catalytic oxidation project ($13 million) and a $7 million increase in labor costs.

- Transmission expense decreased $35 million due to reduced congestion costs.

- Other operating costs increased $39 million due primarily to the assignment of CEI's and TE's leasehold interests in the Bruce Mansfield Plant to FGCO in the fourth quarter of 2007 ($31 million) and reduced life insurance investment values, partially offset by lower associated company billings and employee benefit costs.

- Higher depreciation expenses of $39 million were due to the assignment of the Bruce Mansfield Plant leasehold interests to FGCO and NGC's purchase of certain lessor equity interests in Perry and Beaver Valley Unit 2.

Other Expense –

Total other expense in 2008 was $6 million higher than in 2007, principally due to a $50 million decrease in net earnings from nuclear decommissioning trust investments due primarily to securities impairments resulting from market declines during 2008, partially offset by a decline in interest expense (net of capitalized interest) of $44 million from the repayment of notes to affiliates since 2007.

Other – 2008 Compared to 2007

Our financial results from other operating segments and reconciling items resulted in a $105 million increase in net income in 2008 compared to 2007. The increase resulted primarily from a $19 million after-tax gain from the sale of telecommunication assets, a $10 million after-tax gain from the settlement of litigation relating to formerly-owned international assets, a $41 million reduction in interest expense associated with the revolving credit facility, and income tax adjustments associated with the favorable settlement of tax positions taken on federal returns in prior years. These increases were partially offset by the absence of the gain from the sale of First Communications ($13 million, net of taxes) in 2007.

POSTRETIREMENT BENEFITS

We provide a noncontributory qualified defined benefit pension plan that covers substantially all of our employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. We also provide health care benefits, which include certain employee contributions, deductibles, and co-payments, upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. Our benefit plan assets and obligations are remeasured annually using a December 31 measurement date. Adverse market conditions during 2008 increased 2009 costs, which were partially offset by the effects of a $500 million voluntary cash pension contribution and an OPEB plan amendment in 2009 (see Note 3). Strengthened equity markets during 2007 and a $300 million voluntary cash pension contribution made in 2007 contributed to the reductions in postretirement benefits expenses in 2008. Pension and OPEB expenses are included in various cost categories and have contributed to cost increases discussed above for 2009. The following table reflects the portion of qualified and non-qualified pension and OPEB costs that were charged to expense in the three years ended December 31, 2009:

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

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

SUPPLY PLAN

Regulated Commodity Sourcing

The Utilities have a default service obligation to provide the required power supply to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L's default service supply is secured through a statewide competitive procurement process approved by the NJBPU. The Ohio Utilities and Penn's default service supplies are provided through a competitive procurement process approved by the PUCO and PPUC, respectively. The default service supply for Met-Ed and Penelec is secured through a FERC-approved agreement with FES. If any unaffiliated suppliers fail to deliver power to any one of the Utilities' service areas, the Utility serving that area may need to procure the required power in the market in their role as a PLR.

Unregulated Commodity Sourcing

FES has retail and wholesale competitive load-serving obligations in Ohio, New Jersey, Maryland, Pennsylvania, Michigan and Illinois serving both affiliated and non-affiliated companies. FES provides energy products and services to customers under various PLR, shopping, competitive-bid and non-affiliated contractual obligations. In 2009, FES' generation was used to serve two main obligations -- affiliated companies utilized approximately 76% of its total generation and direct retail customers utilized approximately 18% of FES' total generation. Geographically, approximately 67% of FES' obligation is located in the MISO market area and 33% is located in the PJM market area.

FES provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES controls (either through ownership, lease, affiliated power contracts or participation in OVEC) 14,346 MW of installed generating capacity. FES supplies the power requirements of its competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

CAPITAL RESOURCES AND LIQUIDITY

As of January 31, 2010 we had commitments of approximately $3.4 billion of liquidity including a $2.75 billion revolving credit facility, a $100 million bank line available to FES and $515 million of accounts receivable financing facilities through our Ohio and Pennsylvania utilities. We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations and those of our subsidiaries. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2009 and in subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from the capital markets as market conditions warrant. We also expect that borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

As of December 31, 2009, our net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings ($1.2 billion) and the classification of certain variable interest rate PCRBs as currently payable long-term debt. Currently payable long-term debt as of December 31, 2009, included the following (in millions):

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

(1) Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.
(2) Mature in March 2010.
(3) Mature in November 2010.

Short-Term Borrowings

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

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

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

Revolving Credit Facility

We have the capability to request an increase in the total commitments available under the $2.75 billion revolving credit facility (included in the borrowing capability table above) up to a maximum of $3.25 billion, subject to the discretion of each lender to provide additional commitments. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations.

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of December 31, 2009:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FirstEnergy	$ 2,750	$ - (1)
FES	1,000	- (1)
OE	500	500
Penn	50	33 (2)
CEI	250 (3)	500
TE	250 (3)	500
JCP&L	425	411 (2)
Met-Ed	250	300 (2)
Penelec	250	300 (2)
ATSI	50 (4)	50

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

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

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

(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that ATSI has received regulatory approval to have short-term borrowings up to the same amount.

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

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of December 31, 2009, our debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

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

(1) As of December 31, 2009, FirstEnergy could issue additional debt of approximately $2.5 billion, or recognize a reduction in equity of approximately $1.4 billion, and remain within the limitations of the financial covenants required by its revolving credit facility.

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

FirstEnergy Money Pools

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

Pollution Control Revenue Bonds

As of December 31, 2009, our currently payable long-term debt included approximately $1.6 billion (FES - $1.5 billion, Met-Ed - $29 million and Penelec - $45 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

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

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

(1) Supported by four participating banks, with the LOC bank having 58% of the total commitment.
(2) Supported by 18 participating banks, with no one bank having more than 14% of the total commitment.
(3) Includes approximately $16 million of applicable interest coverage.
(4) Shorter of 6 months or LOC termination date ($155 million) and shorter of one year or LOC termination date ($129 million).

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

Long-Term Debt Capacity

As of December 31, 2009, the Ohio Companies and Penn had the aggregate capability to issue approximately $1.4 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by the Ohio Companies is also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $127 million and $36 million, respectively, as of December 31, 2009. In April 2009, TE issued $300 million of new senior secured notes backed by FMBs. Concurrently with that issuance, and in order to satisfy the limitation on secured debt under its senior note indenture, TE issued an additional $300 million of FMBs to secure $300 million of its outstanding unsecured senior notes originally issued in November 2006. As a result, the provisions for TE to incur additional secured debt do not apply.

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

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

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

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

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

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

Changes in Cash Position

As of December 31, 2009, we had $874 million in cash and cash equivalents compared to $545 million as of December 31, 2008. Cash and cash equivalents consist of unrestricted, highly liquid instruments with an original or remaining maturity of three months or less. As of December 31, 2009 and 2008, FirstEnergy had approximately $12 million and $17 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During 2009, we received $972 million of cash dividends from our subsidiaries and paid $670 million in cash dividends to common shareholders. There are no material restrictions on the payment of cash dividends by our subsidiaries. In addition to paying dividends from retained earnings, each of our electric utility subsidiaries has authorization from the FERC to pay cash dividends from paid-in capital accounts, as long as its debt to total capitalization ratio (without consideration of retained earnings) remains below 65%. CEI and TE are the only utility subsidiaries currently precluded from that action.

Cash Flows from Operating Activities

Our consolidated net cash from operating activities is provided primarily by our energy delivery services and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $2.5 billion in 2009, $2.2 billion in 2008 and $1.7 billion in 2007, as summarized in the following table:

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

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

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

Net cash provided from operating activities increased in 2008 compared to 2007 due to an increase in non-cash charges primarily due to lower deferrals of new regulatory assets and purchased power costs and higher deferred income taxes. The deferral of new regulatory assets decreased primarily as a result of the Ohio Companies' transmission and fuel recovery riders that became effective in July 2007 and January 2008, respectively, and the absence of the deferral of decommissioning costs related to the Saxton nuclear research facility in the first quarter of 2007. Lower deferrals of purchased power costs reflected an increase in the market value of NUG power. The change in deferred income taxes is primarily due to additional tax depreciation under the Economic Stimulus Act of 2008, the settlement of tax positions taken on federal returns in prior years, and the absence of deferred income taxes related to the Bruce Mansfield Unit 1 sale and leaseback transaction in 2007. The changes in working capital and other primarily resulted from changes in accrued taxes of $110 million and prepaid taxes of $278 million, primarily due to increased tax payments. Changes in materials and supplies of $131 million resulted from higher fossil fuel inventories and were partially offset by changes in receivables of $107 million.

Cash Flows From Financing Activities

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

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

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

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

* Issued under the shelf registration statement referenced above.

Cash Flows from Investing Activities

Net cash flows used in investing activities resulted principally from property additions. Additions for the energy delivery services segment primarily include expenditures related to transmission and distribution facilities. Capital spending by the competitive energy services segment is principally generation-related. The following table summarizes investing activities for the three years ended December 31, 2009 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
Sources (Uses)		*(In millions)*		
2009				
Energy delivery services	$ (750)	$ 39	$ (46)	$ (757)
Competitive energy services	(1,262)	(8)	(19)	(1,289)
Other	(149)	(3)	72	(80)
Inter-Segment reconciling items	(42)	(24)	7	(59)
Total	$ (2,203)	$ 4	$ 14	$ (2,185)
2008				
Energy delivery services	$ (839)	$ (41)	$ (17)	$ (897)
Competitive energy services	(1,835)	(14)	(56)	(1,905)
Other	(176)	106	(61)	(131)
Inter-Segment reconciling items	(38)	(12)	-	(50)
Total	$ (2,888)	$ 39	$ (134)	$ (2,983)
2007				
Energy delivery services	$ (814)	$ 53	$ (6)	$ (767)
Competitive energy services	(740)	1,300	-	560
Other	(21)	2	(14)	(33)
Inter-Segment reconciling items	(58)	(15)	-	(73)
Total	$ (1,633)	$ 1,340	$ (20)	$ (313)

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

Net cash used for investing activities in 2008 increased by $2.7 billion compared to 2007. The change was principally due to a $1.3 billion increase in property additions and the absence of $1.3 billion of cash proceeds from the Bruce Mansfield Unit 1 sale and leaseback transaction that occurred in the third quarter of 2007. The increased property additions reflected the acquisitions described above and higher planned AQC system expenditures in 2008. Cash used for other investing activities increased primarily as a result of the 2008 investments in the Signal Peak coal mining project and future-year emission allowances.

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

CONTRACTUAL OBLIGATIONS

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

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

(1) Interest on variable-rate debt based on rates as of December 31, 2009.
(2) See Note 7 to the consolidated financial statements.
(3) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(4) Includes amounts for capital leases (see Note 7) and contingent tax liabilities (see Note 10).

Guarantees and Other Assurances

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

As of December 31, 2009, our maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $4.2 billion, as summarized below:

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

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating-rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $1.6 billion is reflected as currently payable long-term debt on FirstEnergy's consolidated balance sheets.

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

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

(5) Includes approximately $200 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $134 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

We guarantee energy and energy-related payments of our subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. We also provide guarantees to various providers of credit support for the financing or refinancing by our subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate us to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, our guarantee enables the counterparty's legal claim to be satisfied by our other assets. We believe the likelihood is remote that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with ongoing energy and energy-related activities.

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

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

Stress case conditions of a credit rating downgrade or "material adverse event" and hypothetical adverse price movements in the underlying commodity markets would increase the total potential amount to $807 million, consisting of $51 million due to "material adverse event" contractual clauses, $98 million due to an acceleration of payment or funding obligation, and $658 million due to a below investment grade credit rating.

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

In addition to guarantees and surety bonds, FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' power portfolio as of December 31, 2009, and forward prices as of that date, FES had $179 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $129 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

In connection with FES' obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

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

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on our Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $1.7 billion as of December 31, 2009, and December 31, 2008.

We have equity ownership interests in certain businesses that are accounted for using the equity method of accounting for investments. There are no undisclosed material contingencies related to these investments. Certain guarantees that we do not expect to have a material current or future effect on our financial condition, liquidity or results of operations are disclosed under "Guarantees and Other Assurances" above.

MARKET RISK INFORMATION

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

Commodity Price Risk

FirstEnergy is exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices associated with electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. Certain derivatives must be recorded at their fair value and marked to market. The majority of FirstEnergy's derivative hedging contracts qualify for the normal purchase and normal sale exception and are therefore excluded from the tables below. Contracts that are not exempt from such treatment include certain power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978 and certain purchase power contracts (see Note 6). The NUG entities non-trading contracts are adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs or regulatory liability for below-market costs. The change in the fair value of commodity derivative contracts related to energy production during 2009 is summarized in the following table:

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

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

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

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

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

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

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

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

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on its derivative instruments would not have had a material effect on its consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2009. Based on derivative contracts held as of December 31, 2009, an adverse 10% change in commodity prices would decrease net income by approximately $9 million after tax during the next 12 months.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since a significant portion of our debt has fixed interest rates, as noted in the table below.

Comparison of Carrying Value to Fair Value

Year of Maturity	2010	2011	2012	2013	2014	There-after	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 84	$ 79	$ 95	$ 118	$ 110	$ 1,834	$ 2,320	$ 2,413
Average interest rate	7.1 %	7.8 %	7.8 %	7.6 %	8.0 %	4.3 %	5.0 %	
Liabilities								
Long-term Debt:								
Fixed rate	$ 202	$ 336	$ 97	$ 555	$ 529	$ 9,915	$ 11,634	$ 12,350
Average interest rate	5.7 %	6.7 %	7.7 %	5.9 %	5.4 %	6.5 %	6.5 %	
Variable rate	$ 62					$ 2,057	$ 2,119	$ 2,152
Average interest rate	3.3 %					1.8 %	1.8 %	
Short-term Borrowings:	$ 1,181						$ 1,181	$ 1,181
Average interest rate	0.7 %						0.7 %	

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

Interest Rate Swap Agreements – Fair Value Hedges

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

Forward Starting Swap Agreements - Cash Flow Hedges

FirstEnergy uses forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During 2009, FirstEnergy terminated forward swaps with a notional value of $2.8 billion and recognized losses of approximately $18.5 million, of which the ineffective portion recognized as an adjustment to interest expense was immaterial. The remaining effective portions will be amortized to interest expense over the life of the hedged debt.

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

Equity Price Risk

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plan provides defined benefits based on years of service and compensation levels. FirstEnergy also provides health care benefits (which include certain employee contributions, deductibles, and co-payments) upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. In 2009, FirstEnergy remeasured its other postretirement benefit plans on May 31, 2009, and its qualified defined pension plan on August 31, 2009, as discussed below.

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

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

Nuclear decommissioning trust funds have been established to satisfy NGC’s and our Utilities’ nuclear decommissioning obligations. As of December 31, 2009, approximately 16% of the funds were invested in equity securities and 84% were invested in fixed income securities, with limitations related to concentration and investment grade ratings. The equity securities are carried at their market value of approximately $295 million as of December 31, 2009. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $29 million reduction in fair value as of December 31, 2009. The decommissioning trusts of JCP&L and the Pennsylvania Companies are subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NGC, OE and TE recognize in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts as other-than-temporary impairments. On June 18, 2009, the NRC informed FENOC that its review tentatively concluded that a shortfall existed in the decommissioning trust fund for Beaver Valley Unit 1. On November 24, 2009, FENOC submitted a revised decommissioning funding calculation using the NRC formula method based on the renewed license for Beaver Valley Unit 1, which extended operations until 2036. FENOC’s submittal demonstrated that there was a de minimis shortfall. On December 11, 2009, the NRC’s review of FirstEnergy’s methodology for the funding of decommissioning of this facility concluded that there was reasonable assurance of adequate decommissioning funding at the time permanent termination of operations is expected. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

CREDIT RISK

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

We maintain credit policies with respect to our counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of our credit program, we aggressively manage the quality of our portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of December 31, 2009, the largest credit concentration was with Morgan Stanley, which is currently rated investment grade, representing 7.3% of our total approved credit risk.

REGULATORY MATTERS

Regulatory assets that do not earn a current return totaled approximately $187 million as of December 31, 2009 (JCP&L - $36 million, Met-Ed - $114 million, and Penelec - $37 million). Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) are expected to be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec. The following table discloses regulatory assets by company:

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

[1] Penelec had net regulatory liabilities of approximately $137 million as of December 31, 2008. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

Regulatory assets by source are as follows:

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

Ohio

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing. On January 21, 2009, the PUCO granted the Ohio Companies' application in part to increase electric distribution rates by $136.6 million (OE - $68.9 million, CEI - $29.2 million and TE - $38.5 million). These increases went into effect for OE and TE on January 23, 2009, and for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009. The PUCO granted these applications for rehearing on March 18, 2009 for the purpose of further consideration. The PUCO has not yet issued a substantive Entry on Rehearing.

SB221, which became effective on July 31, 2008, required all electric utilities to file an ESP, and permitted the filing of an MRO. On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and a separate MRO. The PUCO denied the MRO application; however, the PUCO later granted the Ohio Companies' application for rehearing for the purpose of further consideration of the matter. The PUCO has not yet issued a substantive Entry on Rehearing. The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. In response to the PUCO's December 19, 2008 order, which significantly modified and approved the ESP as modified, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application in addition to continuing their rate plan then in effect as allowed by the terms of SB221. On December 31, 2008, the Ohio Companies conducted a CBP for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. The average winning bid price was equivalent to a retail rate of 6.98 cents per KWH. The power supply obtained through this process provided generation service to the Ohio Companies' retail customers who chose not to shop with alternative suppliers. On January 9, 2009, the Ohio Companies requested the implementation of a new fuel rider to recover the costs resulting from the December 31, 2008 CBP. The PUCO ultimately approved the Ohio Companies' request for a new fuel rider to recover increased costs resulting from the CBP but denied OE's and TE's request to continue collecting RTC and denied the request to allow the Ohio Companies to continue collections pursuant to the two existing fuel riders. The new fuel rider recovered the increased purchased power costs for OE and TE, and recovered a portion of those costs for CEI, with the remainder being deferred for future recovery.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies. On February 19, 2009, the Ohio Companies filed an Amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties. Specifically, the Amended ESP provided that generation would be provided by FES at the average wholesale rate of the CBP described above for April and May 2009 to the Ohio Companies for their non-shopping customers; for the period of June 1, 2009 through May 31, 2011, retail generation prices would be based upon the outcome of a descending clock CBP on a slice-of-system basis. The Amended ESP further provided that the Ohio Companies will not seek a base distribution rate increase, subject to certain exceptions, with an effective date of such increase before January 1, 2012, that CEI would agree to write-off approximately $216 million of its Extended RTC regulatory asset, and that the Ohio Companies would collect a delivery service improvement rider at an overall average rate of $.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Amended ESP also addressed a number of other issues, including but not limited to, rate design for various customer classes, and resolution of the prudence review and the collection of deferred costs that were approved in prior proceedings. On February 26, 2009, the Ohio Companies filed a Supplemental Stipulation, which was signed or not opposed by virtually all of the parties to the proceeding, that supplemented and modified certain provisions of the February 19, 2009 Stipulation and Recommendation. Specifically, the Supplemental Stipulation modified the provision relating to governmental aggregation and the Generation Service Uncollectible Rider, provided further detail on the allocation of the economic development funding contained in the Stipulation and Recommendation, and proposed additional provisions related to the collaborative process for the development of energy efficiency programs, among other provisions. The PUCO adopted and approved certain aspects of the Stipulation and Recommendation on March 4, 2009, and adopted and approved the remainder of the Stipulation and Recommendation and Supplemental Stipulation without modification on March 25, 2009. Certain aspects of the Stipulation and Recommendation and Supplemental Stipulation took effect on April 1, 2009 while the remaining provisions took effect on June 1, 2009.

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

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

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

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

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

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

Pennsylvania

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations.

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

On May 22, 2008, the PPUC approved Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. The TSCs included a component for under-recovery of actual transmission costs incurred during the prior period (Met-Ed - $144 million and Penelec - $4 million) and transmission cost projections for June 2008 through May 2009 (Met-Ed - $258 million and Penelec - $92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs ($92 million) plus carrying charges for recovery through future TSCs by December 31, 2010. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both Met-Ed and Penelec have concluded. On August 11, 2009, the ALJ issued a Recommended Decision to the PPUC approving Met-Ed's and Penelec's TSCs as filed and dismissing all complaints. Exceptions by various interveners were filed and reply exceptions were filed by Met-Ed and Penelec. On January 28, 2010, the PPUC adopted a motion which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, and instructs Met-Ed and Penelec to work with the parties and file a petition to retain any over-collection, with interest, until 2011 for the purpose of providing mitigation of future rate increases starting in 2011 for their customers. Met-Ed and Penelec are now awaiting an order, which is expected to be consistent with the motion. If so, Met-Ed and Penelec plan to appeal such a decision to the Commonwealth Court of Pennsylvania. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of the companies that they should prevail in any such appeal and therefore expect to fully recover the approximately $170.5 million ($138.7 million for Met-Ed and $31.8 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

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

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

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

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

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

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

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

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

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 30, 2009, the accumulated deferred cost balance totaled approximately $98 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DPA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to those comments. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set. On March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009. This matter is currently pending before the NJBPU.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments. The EMP was issued on October 22, 2008, establishing five major goals:

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

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

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

FERC Matters

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or SECA) during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. A final order is pending before the FERC, and in the meantime, FirstEnergy affiliates have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements. On October 29, 2009, FirstEnergy, with another Company, filed an additional settlement agreement with FERC to resolve their outstanding claims. FirstEnergy is actively pursuing settlement agreements with other parties to the case. On December 8, 2009, certain parties sought a writ of mandamus from the DC Circuit Court of Appeals directing FERC to issue an order on the Initial Decision. The Court agreed to hold this matter in abeyance based upon FERC's representation to use good faith efforts to issue a substantive ruling on the initial decision no later than May 27, 2010. If FERC fails to act, the case will be submitted for briefing in June. The outcome of this matter cannot be predicted.

PJM Transmission Rate

On January 31, 2005, certain PJM transmission owners made filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. Hearings were held on the content of the compliance filings and numerous parties appeared and litigated various issues concerning PJM rate design, notably AEP, which proposed to create a "postage stamp," or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. AEP's proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order (Opinion 494) finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, the FERC's April 19, 2007, and January 31, 2008, orders were appealed to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and another party have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others were consolidated for argument in the Seventh Circuit and the Seventh Circuit Court of Appeals issued a decision on August 6, 2009. The court found that FERC had not marshaled enough evidence to support its decision to allocate costs for new 500+ kV facilities on a postage-stamp basis and, based on this finding, remanded the rate design issue back to FERC. A request for rehearing and rehearing en banc by two Companies was denied by the Seventh Circuit on October 20, 2009. On October 28, 2009, the Seventh Circuit closed its case dockets and returned the case to FERC for further action on the remand order. In an order dated January 21, 2010, FERC set the matter for "paper hearings" – meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments, and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments on April 8, 2010 and May 10, 2010.

The FERC's orders on PJM rate design prevented the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a postage-stamp basis reduces the cost of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement. On November 14, 2008, PJM submitted revisions to its tariff to incorporate cost responsibility assignments for below 500 kV upgrades included in PJM's Regional Transmission Expansion Planning process in accordance with the settlement. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. On November 19, 2009, FERC issued Opinion 503 agreeing that RTEP costs should be allocated on a pro-rata basis to merchant transmission companies. On December 22, 2009, a request for a rehearing of FERC's Opinion No. 503 was made. On January 19, 2010, FERC issued a procedural order noting that FERC would address the rehearing requests in a future order.

RTO Consolidation

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

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

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

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

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

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

Changes ordered for PJM Reliability Pricing Model (RPM) Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, FirstEnergy and other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement discussions. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement, which used the PJM December 12, 2008 filing as its starting point, and stated that unless otherwise specified, provisions filed by PJM on December 12, 2008 apply.

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

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

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn and FES. This requirement was proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. FirstEnergy believes the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. The FERC conditionally approved MISO’s Resource Adequacy proposal on March 26, 2008. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including FirstEnergy, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On April 16, 2009, the FERC issued an additional order on rehearing and compliance, approving MISO’s proposed financial settlement provision for Resource Adequacy. The MISO Resource Adequacy program was implemented as planned and became effective on June 1, 2009, the beginning of the MISO planning year. On June 17, 2009, MISO submitted a compliance filing in response to the FERC’s April 16, 2009 order directing it to address, among others, various market monitoring and mitigation issues. On July 8, 2009, various parties submitted comments on and protests to MISO’s compliance filing. FirstEnergy submitted comments identifying specific aspects of the MISO’s and Independent Market Monitor’s proposals for market monitoring and mitigation and other issues that it believes the FERC should address and clarify. On October 23, 2009, FERC issued an order approving a MISO compliance filing that revised its tariff to provide for netting of demand resources, but prohibiting the netting of behind-the-meter generation.

FES Sales to Affiliates

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

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

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

Reliability Initiatives

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

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

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

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. The initial phase of the investigation required JCP&L to respond to the NERC's request for factual data about the outage. JCP&L submitted its written response on May 1, 2009. The NERC conducted on site interviews with personnel involved in responding to the event on June 16-17, 2009. On July 7, 2009, the NERC issued additional questions regarding the event and JCP&L replied as requested on August 6, 2009. JCP&L is not able at this time to predict what actions, if any, that the NERC may take based on the data submittals or interview results.

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

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on FirstEnergy with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

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

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to $37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

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

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_X and SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices or repowering and provides for stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree, including repowering Burger Units 4 and 5 for biomass fuel consumption, are currently estimated to be $399 million for 2010-2012.

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

In December 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU and Met-Ed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, which the Court granted on March 24, 2009. Specifically, Connecticut and New Jersey allege that "modifications" at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR or permitting under the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. The scope of Met-Ed's indemnity obligation to and from Sithe Energy is disputed. Met-Ed filed a Motion to Dismiss the claims in New Jersey's Amended Complaint and Connecticut's Complaint in February and September of 2009, respectively. The Court granted Met-Ed's motion to dismiss New Jersey's and Connecticut's claims for injunctive relief against Met-Ed, but denied Met-Ed's motion to dismiss the claims for civil penalties on statute of limitations grounds in order to allow the states to prove either that the application of the discovery rule or the doctrine of equitable tolling bars application of the statute of limitations.

In January 2009, the EPA issued a NOV to Reliant alleging NSR violations at the Portland Generation Station based on "modifications" dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA's January 2009, NOV also alleged NSR violations at the Keystone and Shawville Stations based on "modifications" dating back to 1984. JCP&L, as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

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

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

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

National Ambient Air Quality Standards

In March 2005, the EPA finalized CAIR, covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia, based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR requires reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NO_X emissions to 1.3 million tons annually. CAIR was challenged in the U.S. Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." In September 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. In December 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. On July 10, 2009, the U.S. Court of Appeals for the District of Columbia ruled in a different case that a cap-and-trade program similar to CAIR, called the "NO_X SIP Call," cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the "8-hour" ozone NAAQS. FGCO's future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_X emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the U.S. Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition in May 2008. In October 2008, the EPA (and an industry group) petitioned the U.S. Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the EPA moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the EPA's petition and denied the industry group's petition. On October 21, 2009, the EPA opened a 30-day comment period on a proposed consent decree that would obligate the EPA to propose MACT regulations for mercury and other hazardous air pollutants by March 16, 2011, and to finalize the regulations by November 16, 2011. FGCO's future cost of compliance with MACT regulations may be substantial and will depend on the action taken by the EPA and on how any future regulations are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On December 23, 2009, the Supreme Court of Pennsylvania affirmed the Commonwealth Court of Pennsylvania ruling that Pennsylvania's mercury rule is "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing, by 2012, the amount of man-made GHG, including CO_2, emitted by developed countries. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, the December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement which recognized the scientific view that the increase in global temperature should be below two degrees Celsius, included a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020, and established the "Copenhagen Green Climate Fund" to support mitigation, adaptation, and other climate-related activities in developing countries. Once they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia, and the United States, would commit to quantified economy-wide emissions targets from 2020, while developing countries, including Brazil, China, and India, would agree to take mitigation actions, subject to their domestic measurement, reporting, and verification. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, on June 26, 2009. The Senate continues to consider a number of measures to regulate GHG emissions. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states, led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as "air pollutants" under the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate "air pollutants" from those and other facilities. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that the atmospheric concentrations of several key GHG threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key GHG and hence to the threat of climate change. Although the EPA's finding does not establish emission requirements for motor vehicles, such requirements are expected to occur through further rulemakings. Additionally, while the EPA's endangerment findings do not specifically address stationary sources, including electric generating plants EPA's expected establishment of emission requirements for motor vehicles would be expected to support the establishment of future emission requirements by the EPA for stationary sources. In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that will require FirstEnergy to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. Also in September 2009, EPA proposed new thresholds for GHG emissions that define when CAA permits under the NSR and Title V operating permits programs would be required. EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) for existing facilities under the Title V operating permits program and the Prevention of Significant Determination (PSD) portion of NSR. EPA is also proposing a significance level between 10,000 and 25,000 tpy CO2e to determine if existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit.

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

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

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 1, 2009, the Supreme Court of the United States reversed one significant aspect of the Second Circuit Court's opinion and decided that Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. FirstEnergy is studying various control options and their costs and effectiveness. Depending on the results of such studies and the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

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

Regulation of Waste Disposal

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. In February 2009, the EPA requested comments from the states on options for regulating coal combustion wastes, including regulation as non-hazardous waste or regulation as a hazardous waste. In March and June 2009, the EPA requested information from FGCO's Bruce Mansfield Plant regarding the management of coal combustion wastes. In December 2009, EPA provided to FGCO the findings of its review of the Bruce Mansfield Plant's coal combustion waste management practices. EPA observed that the waste management structures and the Plant "appeared to be well maintained and in good working order" and recommended only that FGCO "seal and maintain all asphalt surfaces." On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. Additional regulations of fossil-fuel combustion waste products could have a significant impact on our management, beneficial use, and disposal, of coal ash. FGCO's future cost of compliance with any coal combustion waste regulations which may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the states.

The Utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of December 31, 2009, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $101 million (JCP&L - $74 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FirstEnergy - $24 million) have been accrued through December 31, 2009. Included in the total are accrued liabilities of approximately $67 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

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. The class was decertified twice by the trial court, and appealed both times by the Plaintiffs, with the results being that: (1) the Appellate Division limited the class only to those customers directly impacted by the outages of JCP&L transformers in Red Bank, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation which resulted in planned and unplanned outages in the area during a 2-3 day period, and (2) in March 2007, the Appellate Division remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. On March 31, 2009, the trial court again granted JCP&L's motion to decertify the class. On April 20, 2009, the Plaintiffs filed a motion for leave to take an interlocutory appeal to the trial court's decision to decertify the class, which was granted by the Appellate Division on June 15, 2009. Plaintiffs filed their appellate brief on August 25, 2009, and JCP&L filed an opposition brief on September 25, 2009. On or about October 13, 2009, Plaintiffs filed their reply brief in further support of their appeal of the trial court's decision decertifying the class. The Appellate Division heard oral argument on January 5, 2010, before a three-judge panel. JCP&L is awaiting the Court's decision.

Nuclear Plant Matters

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. On November 5, 2009, the NRC issued a renewed operating license for Beaver Valley Power Station, Units 1 and 2. The operating licenses for these facilities were extended until 2036 and 2047 for Units 1 and 2, respectively.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2009, FirstEnergy had approximately $1.9 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy provided an additional $80 million parental guarantee associated with the funding of decommissioning costs for these units and indicated that it planned to contribute an additional $80 million to these trusts by 2010. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy's nuclear decommissioning trusts fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and its effects on particular businesses and the economy in general also affects the values of the nuclear decommissioning trusts. On June 18, 2009, the NRC informed FENOC that its review tentatively concluded that a shortfall existed in the decommissioning trust fund for Beaver Valley Unit 1. On November 24, 2009, FENOC submitted a revised decommissioning funding calculation using the NRC formula method based on the renewed license for Beaver Valley Unit 1, which extended operations until 2036. FENOC's submittal demonstrated that there was a de minimis shortfall. On December 11, 2009, the NRC's review of FirstEnergy's methodology for the funding of decommissioning of this facility concluded that there was reasonable assurance of adequate decommissioning funding at the time permanent termination of operations is expected. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

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.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. A final order identifying the individual damage amounts was issued on October 31, 2007 and the award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. On February 25, 2009, the federal district court denied JCP&L's motion to vacate the arbitration decision and granted the union's motion to confirm the award. JCP&L filed a Notice of Appeal to the Third Circuit and a Motion to Stay Enforcement of the Judgment on March 6, 2009. The appeal process could take as long as 24 months. The parties are participating in the federal court's mediation programs and have held private settlement discussions. JCP&L recognized a liability for the potential $16 million award in 2005. Post-judgment interest began to accrue as of February 25, 2009, and the liability will be adjusted accordingly.

FirstEnergy 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

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

Revenue Recognition

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

Regulatory Accounting

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

Pension and Other Postretirement Benefits Accounting

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

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

In accordance with 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.

We recognize the overfunded or underfunded status of our defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The underfunded status of our qualified and non-qualified pension and OPEB plans at December 31, 2009 is $1.3 billion.

In selecting an assumed discount rate, we consider currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. As of December 31, 2009, the assumed discount rates for pension and OPEB were 6.0% and 5.75%, respectively. The assumed discount rates for both pension and OPEB were 7.0% and 6.5% as of December 31, 2008, and 2007, respectively.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. In 2009 our qualified pension and OPEB plan assets actually earned $570 million or 13.6% and lost $1.4 billion or 23.8% in 2008. Our qualified pension and OPEB costs in 2009 and 2008 were computed using an assumed 9.0% rate of return on plan assets which generated $379 million and $514 million of expected returns on plan assets, respectively. The expected return of pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension and OPEB cost, respectively.

Our qualified and non-qualified pension and OPEB net periodic benefit cost was $197 million in 2009 compared to credits of $116 million in 2008 and $73 million in 2007. 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, we elected to remeasure our qualified pension plan as of August 31, 2009. On January 2, 2007, we made a $300 million voluntary contribution to our pension plan. In addition, during 2006, we amended our OPEB plan, effective in 2008, to cap our monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. On June 2, 2009, we further amended our 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. 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. We expect our 2010 qualified and non-qualified pension and OPEB costs (including amounts capitalized) to be $138 million.

Health care cost trends continue to increase and will affect future OPEB costs. The 2009 and 2008 composite health care trend rate assumptions were approximately 8.5-10% and 9-11%, respectively, gradually decreasing to 5% in later years. In determining our trend rate assumptions, we included the specific provisions of our health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in our health care plans, and projections of future medical trend rates. The effect on our pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by 0.25%	$ 12	$ 1	$ 13
Long-term return on assets	Decrease by 0.25%	$ 11	$ 1	$ 12
Health care trend rate	Increase by 1%	N/A	$ 4	$ 4

Emission Allowances

We hold 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 to us by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at the lesser of weighted average cost or market value. Emission allowances eligible for use in future years are recorded as other investments. We recognize emission allowance costs as fuel expense during the periods that emissions are produced by our generating facilities. Excess emission allowances that are not needed to meet emission requirements may be sold and are reported as a reduction to other operating expenses.

Long-Lived Assets

We review 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 an 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

We recognize an ARO for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all of our long-lived assets. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants' current license and 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. Based on the guidance provided by accounting standards for the recognition, subsequent measurement, and subsequent recognition of goodwill, we evaluate goodwill for impairment at least annually and make such evaluations more frequently if indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated, we recognize a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. The forecasts used in our evaluations of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

In 2009, the FASB amended the derecognition guidance in the Transfers and Servicing Topic of the FASB Accounting Standards Codification and eliminated the concept of a QSPE. The amended guidance requires an evaluation of all existing QSPEs to determine whether they must be consolidated. This standard is effective for financial asset transfers that occur in fiscal years beginning after November 15, 2009. FirstEnergy does not expect this standard to have a material effect upon its financial statements.

In 2009, the FASB amended the consolidation guidance applied to VIEs. This standard replaces the quantitative approach previously required to determine which entity has a controlling financial interest in a VIE with a qualitative approach. Under the new approach, the primary beneficiary of a VIE is the entity that has both (a) the power to direct the activities of the VIE that most significantly impact the entity's economic performance, and (b) the obligation to absorb losses of the entity, or the right to receive benefits from the entity, that could be significant to the VIE. This standard also requires ongoing reassessments of whether an entity is the primary beneficiary of a VIE and enhanced disclosures about an entity's involvement in VIEs. The standard is effective for fiscal years beginning after November 15, 2009. FirstEnergy does not expect this standard to have a material effect upon its financial statements.

In 2010, the FASB amended the Fair Value Measurements and Disclosures Topic of the FASB Accounting Standards Codification to require additional disclosures about 1) transfers of Level 1 and Level 2 fair value measurements, including the reason for transfers, 2) purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, 3) additional disaggregation to include fair value measurement disclosures for each class of assets and liabilities and 4) disclosure of inputs and valuation techniques used to measure fair value for both recurring and nonrecurring fair value measurements. The amendment is effective for fiscal years beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, which is effective for fiscal years beginning after December 15, 2010. FirstEnergy does not expect this standard to have a material effect upon its financial statements.

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 2009 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 2009.

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, 2009. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 64.

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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 18, 2010

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2009	2008	2007
	(In millions, except per share amounts)		
REVENUES:			
Electric utilities	$ 11,139	$ 12,061	$ 11,305
Unregulated businesses	1,828	1,566	1,497
Total revenues*	12,967	13,627	12,802
EXPENSES:			
Fuel	1,153	1,340	1,178
Purchased power	4,730	4,291	3,836
Other operating expenses	2,697	3,045	3,083
Provision for depreciation	736	677	638
Amortization of regulatory assets	1,155	1,053	1,019
Deferral of regulatory assets	(136)	(316)	(524)
General taxes	753	778	754
Total expenses	11,088	10,868	9,984
OPERATING INCOME	1,879	2,759	2,818
OTHER INCOME (EXPENSE):			
Investment income, net	204	59	120
Interest expense	(978)	(754)	(775)
Capitalized interest	130	52	32
Total other expense	(644)	(643)	(623)
INCOME BEFORE INCOME TAXES	1,235	2,116	2,195
INCOME TAXES	245	777	883
NET INCOME	990	1,339	1,312
Noncontrolling interest income (loss)	(16)	(3)	3
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 1,006	$ 1,342	$ 1,309
BASIC EARNINGS PER SHARE OF COMMON STOCK	$ 3.31	$ 4.41	$ 4.27
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	304	304	306
DILUTED EARNINGS PER SHARE OF COMMON STOCK	$ 3.29	$ 4.38	$ 4.22
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	306	307	310

* Includes $395 million, $432 million and $425 million of excise tax collections in 2009, 2008 and 2007, respectively.

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

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

As of December 31,	2009	2008
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 874	$ 545
Receivables-		
Customers (less accumulated provisions of $33 million and $28 million, respectively, for uncollectible accounts)	1,244	1,304
Other (less accumulated provisions of $7 million and $9 million, respectively, for uncollectible accounts)	153	167
Materials and supplies, at average cost	647	605
Prepaid taxes	248	283
Other	154	149
	3,320	3,053
PROPERTY, PLANT AND EQUIPMENT:		
In service	27,826	26,482
Less - Accumulated provision for depreciation	11,397	10,821
	16,429	15,661
Construction work in progress	2,735	2,062
	19,164	17,723
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,859	1,708
Investments in lease obligation bonds (Note 7)	543	598
Other	621	711
	3,023	3,017
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,575	5,575
Regulatory assets	2,356	3,140
Power purchase contract asset	200	434
Other	666	579
	8,797	9,728
	$ 34,304	$ 33,521
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,834	$ 2,476
Short-term borrowings (Note 14)	1,181	2,397
Accounts payable	829	794
Accrued taxes	314	333
Other	1,130	1,098
	5,288	7,098
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 375,000,000 shares- 304,835,407 outstanding	31	31
Other paid-in capital	5,448	5,473
Accumulated other comprehensive loss	(1,415)	(1,380)
Retained earnings	4,495	4,159
Total common stockholders' equity	8,559	8,283
Noncontrolling interest	(2)	32
Total equity	8,557	8,315
Long-term debt and other long-term obligations (Note 12(C))	11,908	9,100
	20,465	17,415
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,468	2,163
Asset retirement obligations	1,425	1,335
Deferred gain on sale and leaseback transaction	993	1,027
Power purchase contract liability	643	766
Retirement benefits	1,534	1,884
Lease market valuation liability	262	308
Other	1,226	1,525
	8,551	9,008
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 7 and 15)		
	$ 34,304	$ 33,521

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
			(Dollars in millions)				
Balance, January 1, 2007		319,205,517	$ 32	$ 6,466	$ (259)	$ 2,806	$ (10)
Earnings available to FirstEnergy Corp.	$ 1,309					1,309	
Unrealized loss on derivative hedges, net of $8 million of income tax benefits	(17)				(17)		
Unrealized gain on investments, net of $31 million of income taxes	47				47		
Pension and other postretirement benefits, net of $169 million of income taxes (Note 3)	179				179		
Comprehensive income	$ 1,518						
Stock options exercised				(40)			
Allocation of ESOP shares				26			10
Restricted stock units				23			
Stock-based compensation				2			
Accounting for uncertainty in income taxes cumulative effect adjustment						(3)	
Repurchase of common stock		(14,370,110)	(1)	(968)			
Cash dividends declared on common stock						(625)	
Balance, December 31, 2007		304,835,407	31	5,509	(50)	3,487	-
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	$ -

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2009	2008	2007
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 990	$ 1,339	$ 1,312
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	736	677	638
Amortization of regulatory assets	1,155	1,053	1,019
Deferral of regulatory assets	(136)	(316)	(524)
Nuclear fuel and lease amortization	128	112	101
Deferred purchased power and other costs	(338)	(226)	(350)
Deferred income taxes and investment tax credits, net	384	366	(9)
Investment impairment	62	123	26
Deferred rents and lease market valuation liability	(52)	(95)	(99)
Stock based compensation	20	(64)	(39)
Accrued compensation and retirement benefits	22	(140)	(37)
Gain on asset sales	(27)	(72)	(30)
Electric service prepayment programs	(10)	(77)	(75)
Cash collateral, net	30	(31)	(68)
Gain on sales of investment securities held in trusts, net	(176)	(63)	(10)
Loss on debt redemption	146	-	-
Commodity derivative transactions, net (Note 6)	229	5	6
Pension trust contributions	(500)	-	(300)
Uncertain tax positions	(210)	(5)	19
Decrease (increase) in operating assets-			
Receivables	75	(29)	(136)
Materials and supplies	(11)	(52)	79
Prepayments and other current assets	(19)	(263)	10
Increase (decrease) in operating liabilities-			
Accounts payable	50	10	51
Accrued taxes	(103)	(39)	48
Accrued interest	67	4	(8)
Other	(47)	7	75
Net cash provided from operating activities	2,465	2,224	1,699
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	4,632	1,367	1,520
Short-term borrowings, net	-	1,494	-
Redemptions and Repayments-			
Common stock	-	-	(969)
Long-term debt	(2,610)	(1,034)	(1,070)
Short-term borrowings, net	(1,246)	-	(205)
Common stock dividend payments	(670)	(671)	(616)
Other	(57)	19	(7)
Net cash provided from (used for) financing activities	49	1,175	(1,347)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,203)	(2,888)	(1,633)
Proceeds from asset sales	21	72	42
Proceeds from sale and leaseback transaction	-	-	1,329
Sales of investment securities held in trusts	2,229	1,656	1,294
Purchases of investment securities held in trusts	(2,306)	(1,749)	(1,397)
Cash investments (Note 5)	60	60	72
Other	14	(134)	(20)
Net cash used for investing activities	(2,185)	(2,983)	(313)
Net increase in cash and cash equivalents	329	416	39
Cash and cash equivalents at beginning of year	545	129	90
Cash and cash equivalents at end of year	$ 874	$ 545	$ 129
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 718	$ 667	$ 744
Income taxes	$ 173	$ 685	$ 710

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

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 February 18, 2010, 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 16). 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, 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 benefit costs	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)
Fuel 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
December 31, 2008*							
Regulatory transition costs	$ 1,452	$ 112	$ 80	$ 12	$ 1,236	$ 12	$ -
Customer shopping incentives	420	-	420	-	-	-	-
Customer receivables for future income taxes	245	68	4	1	59	113	-
Loss (Gain) on reacquired debt	51	20	1	(3)	24	9	-
Employee postretirement benefit costs	31	-	7	3	13	8	-
Nuclear decommissioning, decontamination and spent fuel disposal costs	(57)	-	-	-	(2)	(55)	-
Asset removal costs	(215)	(15)	(36)	(16)	(148)	-	-
MISO/PJM transmission costs	389	31	19	20	-	319	-
Fuel costs	214	109	75	30	-	-	-
Distribution costs	475	222	198	55	-	-	-
Other	135	28	16	7	46	7	-
Total	$ 3,140	$ 575	$ 784	$ 109	$ 1,228	$ 413	$ -

* Penelec had net regulatory liabilities of approximately $137 million as of December 31, 2008. These net regulatory liabilities are included in Other Non-Current Liabilities on the Consolidated Balance Sheets.

Regulatory assets that do not earn a current return (primarily for certain regulatory transition costs and employee postretirement benefits) totaled approximately $187 million as of December 31, 2009 (JCP&L - $36 million, Met-Ed - $114 million, and Penelec - $37 million). Regulatory assets not earning a current return will be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec.

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 $369 million for JCP&L (recovered through NGC revenues) and $110 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 11).

(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 sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2009 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2009 and 2008 are shown below.

Customer Receivables	FE	FES	OE	CEI	TE[1]	JCP&L	Met-Ed	Penelec
December 31, 2009				*(In millions)*				
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
December 31, 2008								
Billed	$ 752	$ 84	$ 143	$ 150	$ 1	$ 179	$ 93	$ 86
Unbilled	552	2	134	126	-	161	67	61
Total	$ 1,304	$ 86	$ 277	$ 276	$ 1	$ 340	$ 160	$ 147

[1] See Note 14 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 is computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. In 2007, FirstEnergy repurchased approximately 14.4 million shares, or 4.5%, of its outstanding common stock for $951 million through an accelerated share repurchase program. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2009	2008	2007
	(In millions, except per share amounts)		
Earnings available to FirstEnergy Corp.	$ 1,006	$ 1,342	$ 1,309
Average shares of common stock outstanding – Basic	304	304	306
Assumed exercise of dilutive stock options and awards	2	3	4
Average shares of common stock outstanding – Diluted	306	307	310
Basic earnings per share of common stock:	$ 3.31	$ 4.41	$ 4.27
Diluted earnings per share of common stock:	$ 3.29	$ 4.38	$ 4.22

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which were 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's recognizes liabilities for planned major maintenance projects as they are incurred. Property, plant and equipment balances as of December 31, 2009 and 2008 were as follows:

	December 31, 2009			December 31, 2008		
Property, Plant and Equipment	Unregulated	Regulated	Total	Unregulated	Regulated	Total
			(In millions)			
In service	$ 10,935	$ 16,891	$ 27,826	$ 10,236	$ 16,246	$ 26,482
Less accumulated depreciation	(4,699)	(6,698)	(11,397)	(4,403)	(6,418)	(10,821)
Net plant in service	$ 6,236	$ 10,193	$ 16,429	$ 5,833	$ 9,828	$ 15,661

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 2009, 2008, and 2007 are shown in the following table:

	Annual Composite Depreciation Rate		
	2009	2008	2007
OE	3.1 %	3.1 %	2.9 %
CEI	3.3	3.5	3.6
TE	3.3	3.6	3.9
Penn	2.4	2.4	2.3
JCP&L	2.4	2.3	2.1
Met-Ed	2.5	2.3	2.3
Penelec	2.6	2.5	2.3
FGCO	4.6	4.7	4.0
NGC	3.0	2.8	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 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 13.

(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 an 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.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by accounting standards for the recognition and subsequent measurement of goodwill, we evaluate goodwill for impairment at least annually and make such evaluations more frequently if indicators of impairment arise. If the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated a loss is recognized– calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill.

The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. FirstEnergy's goodwill primarily relates to its energy delivery services segment.

FirstEnergy's 2009 annual review was completed as of July 31, with no impairment indicated.

FirstEnergy's 2008 annual review was completed in the third quarter of 2008 with no impairment indicated. Due to the significant downturn in the U.S. economy during the fourth quarter of 2008, goodwill was tested for impairment as of December 31, 2008. No impairment was indicated for the former GPU companies. As discussed in Note 11(B) on February 19, 2009, the Ohio Companies filed an application for an amended ESP, which substantially reflected terms proposed by the PUCO Staff on February 2, 2009. Goodwill for the Ohio Companies was tested as of December 31, 2008, reflecting the projected results associated with the amended ESP. No impairment was indicated for the Ohio Companies. The PUCO's final decision did not result in an additional impairment charge. During 2008, FirstEnergy adjusted goodwill of the former GPU companies by $32 million due to the realization of tax benefits that had been reserved under purchase accounting.

In 2007, FirstEnergy adjusted goodwill for the former GPU companies by $290 million due to the realization of tax benefits that had been reserved in purchase accounting.

A summary of the changes in goodwill for the three years ended December 31, 2009 is shown below by operating segment, which represent aggregated reporting units (see Note 16 - Segment Information):

	Energy Delivery Services	Competitive Energy Services	Other	Consolidated
		(In millions)		
Balance as of January 1, 2007	$ 5,873	$ 24	$ 1	$ 5,898
Adjustments related to GPU acquisition	(290)	-	-	(290)
Other	-	-	(1)	(1)
Balance as of December 31, 2007	5,583	24	-	5,607
Adjustments related to GPU acquisition	(32)	-	-	(32)
Balance as of December 31, 2008 and 2009	$ 5,551	$ 24	$ -	$ 5,575

A summary of the changes in FES' and the Utilities' goodwill for the three years ended December 31, 2009 is shown below.

Goodwill	FES	CEI	TE	JCP&L	Met-Ed	Penelec
			(In millions)			
Balance as of January 1, 2007	$ 24	$ 1,689	$ 501	$ 1,962	$ 496	$ 861
Adjustments related to GPU acquisition	-	-	-	(136)	(72)	(83)
Balance as of December 31, 2007	24	1,689	501	1,826	424	778
Adjustments related to GPU acquisition	-	-	-	(15)	(8)	(9)
Balance as of December 31, 2008 and 2009	$ 24	$ 1,689	$ 501	$ 1,811	$ 416	$ 769

FirstEnergy, FES and the Utilities, with the exception of Met-Ed as noted below, have no accumulated impairment charge as of December 31, 2009. 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 2009, 2008 and 2007, FirstEnergy recognized $62 million, $123 million and $26 million, respectively, of other-than-temporary impairments. The fair value of FirstEnergy's investments are disclosed in Note 5(B).

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with stockholders and 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, 2009 and 2008, 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	$ (1,341)	$ (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)
Net liability for unfunded retirement benefits	$ (1,322)	$ (97)	$ (190)	$ (135)	$ (43)	$ (215)	$ (140)	$ (128)
Unrealized gain on investments	45	30	6	-	10	-	-	-
Unrealized loss on derivative hedges	(103)	(25)	-	-	-	(2)	(1)	-
AOCL Balance, December 31, 2008	$ (1,380)	$ (92)	$ (184)	$ (135)	$ (33)	$ (217)	$ (141)	$ (128)

Other comprehensive income (loss) reclassified to net income during the three years ended December 31, 2009, 2008 and 2007 was as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
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
2007								
Pension and other postretirement benefits	$ 45	$ 5	$ 14	$ (5)	$ (2)	$ 8	$ 6	$ 11
Gain on investments	10	10	-	-	-	-	-	-
Loss on derivative hedges	(26)	(12)	-	-	-	-	-	-
	29	3	14	(5)	(2)	8	6	11
Income taxes (benefits) related to reclassification to net income	14	1	6	(2)	(1)	4	3	5
Reclassification to net income	$ 15	$ 2	$ 8	$ (3)	$ (1)	$ 4	$ 3	$ 6

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 estimates that additional cash contributions will not be required by law before 2012.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. During 2008, FirstEnergy further amended the OPEB plan effective in 2010 to limit the monthly contribution for pre-1990 retirees. 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.

Obligations and Funded Status As of December 31	Pension Benefits 2009	Pension Benefits 2008	Other Benefits 2009	Other Benefits 2008
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,700	$ 4,750	$ 1,189	$ 1,182
Service cost	91	87	12	19
Interest cost	317	299	64	74
Plan participants' contributions	-	-	29	25
Plan amendments	6	6	(408)	(20)
Special termination benefits	-	-	13	-
Medicare retiree drug subsidy	-	-	20	2
Actuarial (gain) loss	648	(152)	23	12
Benefits paid	(370)	(290)	(119)	(105)
Benefit obligation as of December 31	$ 5,392	$ 4,700	$ 823	$ 1,189
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 3,752	$ 5,285	$ 440	$ 618
Actual return on plan assets	508	(1,251)	62	(152)
Company contributions	509	8	55	54
Plan participants' contributions	-	-	29	25
Benefits paid	(370)	(290)	(119)	(105)
Fair value of plan assets as of December 31	$ 4,399	$ 3,752	$ 467	$ 440
Funded Status				
Qualified plan	$ (787)	$ (774)		
Non-qualified plans	(206)	(174)		
Funded status	$ (993)	$ (948)	$ (356)	$ (749)
Accumulated benefit obligation	$ 5,036	$ 4,367		
Amounts Recognized on the Balance Sheet				
Current liabilities	$ (10)	$ (8)	$ -	$ -
Noncurrent liabilities	(983)	(940)	(356)	(749)
Net liability as of December 31	$ (993)	$ (948)	$ (356)	$ (749)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 67	$ 80	$ (1,145)	$ (912)
Actuarial loss	2,486	2,182	756	801
Net amount recognized	$ 2,553	$ 2,262	$ (389)	$ (111)
Assumptions Used to Determine Benefit Obligations as of December 31				
Discount rate	6.00%	7.00%	5.75%	7.00%
Rate of compensation increase	5.20%	5.20%		
Allocation of Plan Assets As of December 31				
Equity securities	39%	47%	51%	56%
Bonds	49	38	46	38
Real estate	6	9	1	2
Private equities	5	3	1	1
Cash	1	3	1	3
Total	100%	100%	100%	100%

Estimated 2010 Amortization of Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$ 13	$ (193)
Actuarial loss	$ 188	$ 60

Components of Net Periodic Benefit Costs	Pension Benefits 2009	2008	2007	Other Benefits 2009	2008	2007
			(In millions)			
Service cost	$ 91	$ 87	$ 88	$ 12	$ 19	$ 21
Interest cost	317	299	294	64	74	69
Expected return on plan assets	(343)	(463)	(449)	(36)	(51)	(50)
Amortization of prior service cost	13	13	13	(175)	(149)	(149)
Amortization of net actuarial loss	179	8	45	61	47	45
Net periodic cost	$ 257	$ (56)	$ (9)	$ (74)	$ (60)	$ (64)

FES' and the Utilities' shares of the net pension and OPEB asset (liability) as of December 31, 2009 and 2008 are as follows:

Net Pension and OPEB Asset (Liability)	Pension Benefits 2009	2008	Other Benefits 2009	2008
		(In millions)		
FES	$ (361)	$ (193)	$ (19)	$ (124)
OE	30	(38)	(74)	(167)
CEI	(13)	(27)	(59)	(93)
TE	(15)	(12)	(47)	(59)
JCP&L	(77)	(128)	(56)	(58)
Met-Ed	6	(89)	(28)	(52)
Penelec	(79)	(64)	(84)	(103)

FES' and the Utilities' shares of the net periodic pension and OPEB costs for the three years ended December 31, 2009 are as follows:

Net Periodic Pension and OPEB Costs	Pension Benefits 2009	2008	2007	Other Benefits 2009	2008	2007
			(In millions)			
FES	$ 71	$ 15	$ 21	$ (15)	$ (7)	$ (10)
OE	23	(26)	(16)	(14)	(7)	(11)
CEI	17	(5)	1	-	2	4
TE	6	(3)	-	2	4	5
JCP&L	31	(15)	(9)	(6)	(16)	(16)
Met-Ed	18	(10)	(7)	(4)	(10)	(10)
Penelec	16	(13)	(10)	(4)	(13)	(13)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2009	2008	2007	Other Benefits 2009	2008	2007
Weighted-average discount rate	7.00%	6.50%	6.00%	7.00%	6.50%	6.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	5.20%	5.20%	3.50%			

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. Real estate investment trusts' and certain fixed income securities' market values 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 in nature to the ones being valued.

As of December 31, 2009, the pension investments measured at fair value were as follows:

	December 31, 2009				Asset Allocation
	Level 1	Level 2	Level 3	Total	
Assets		*(in millions)*			
Short-term securities	$ -	$ 337	$ -	$ 337	7%
Common and preferred stocks	578	994	-	1,572	36%
Mutual funds	159	-	-	159	4%
Bonds	-	1,928	-	1,928	44%
Real estate/other assets	1	4	378	383	9%
	$ 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 2009:

	Real estate / Other assets
	(in millions)
Beginning balance	$ 416
Transfers	44
Acquisitions/(Dispositions)	16
Loss	(98)
Ending balance	$ 378

As of December 31, 2009, the other postretirement benefit investments measured at fair value were as follows:

	December 31, 2009				Asset Allocation
	Level 1	Level 2	Level 3	Total	
Assets		*(in millions)*			
Short-term securities	$ -	$ 19	$ -	$ 19	4%
Common and preferred stocks	172	53	-	225	47%
Mutual funds	10	2	-	12	3%
Bonds	-	208	-	208	44%
Real estate/other assets	-	-	11	11	2%
	$ 182	$ 282	$ 11	$ 475	100%

The following table provides a reconciliation of changes in the fair value of the other postretirement benefit investments classified as Level 3 in the fair value hierarchy during 2009:

	Real estate / Other assets
	(in millions)
Beginning balance	$ 12
Transfers	1
Acquisitions/(Dispositions)	1
Loss	(3)
Ending balance	$ 11

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 2009 and 2008 are shown in the following table:

	Target Asset Allocations	
	2009	2008
Equities	58%	58%
Fixed income	30%	30%
Real estate	8%	8%
Private equity	4%	4%
Total	100%	100%

Assumed Health Care Cost Trend Rates As of December 31	2009	2008
Health care cost trend rate assumed for next year (pre/post-Medicare)	8.5-10%	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	2015-2017

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 3	$ (2)
Effect on accumulated postretirement benefit obligation	$ 20	$ (18)

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)	
2010	$ 316	$ 85
2011	324	87
2012	336	58
2013	346	51
2014	364	53
Years 2015- 2019	1,999	273

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs – LTIP, EDCP, ESOP and DCPD. In 2001, FirstEnergy also assumed responsibility for two stock-based plans as a result of its acquisition of GPU. No further stock-based compensation can be awarded under GPU's Stock Option and Restricted Stock Plan for MYR Group Inc. Employees (MYR Plan) or 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries (GPU Plan). All options and restricted stock under both plans have been converted into FirstEnergy options and restricted stock. Options under the GPU Plan became fully vested on November 7, 2001, and will expire on or before June 1, 2010.

(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, 2009, 7.9 million shares were available for future awards.

FirstEnergy records the actual tax benefit realized for tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2009, 2008, and 2007 were $9 million, $43 million, and $34 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded to stockholders' equity and reported as an other financing activity within the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Eligible employees receive awards of FirstEnergy common stock or stock units subject to restrictions. Those restrictions lapse over a defined period of time or based on performance. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted common stock grants under the LTIP were as follows:

	2009	2008	2007
Restricted common shares granted	73,255	82,607	77,388
Weighted average market price	$ 43.68	$ 68.98	$ 67.98
Weighted average vesting period (years)	4.42	5.03	4.61
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during the year was as follows (forfeitures were not material):

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2009	667,933	$ 49.54
Nonvested as of December 31, 2009	648,293	48.84
Granted in 2009	73,255	43.68
Vested in 2009	85,881	42.73

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.

	2009	2008	2007
Restricted common share units granted	533,399	450,683	412,426
Weighted average vesting period (years)	3.00	3.14	3.22

Vesting activity for restricted stock units during the year was as follows (forfeitures were not material):

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2009	1,011,054	$ 62.02
Nonvested as of December 31, 2009	1,031,050	60.10
Granted in 2009	533,399	41.40
Vested in 2009	457,536	42.53

Compensation expense recognized in 2009, 2008 and 2007 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $25 million, $29 million and $24 million, respectively.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activities under FirstEnergy stock option programs for 2009 were as follows:

Stock Option Activities	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2009 (3,266,408 options exercisable)	3,266,408	$ 34.56
Options granted	-	-
Options exercised	178,133	32.53
Options forfeited	21,075	30.50
Balance, December 31, 2009 (3,067,200 options exercisable)	3,067,200	$ 34.70

Options outstanding by plan and range of exercise price as of December 31, 2009 were as follows:

		Options Outstanding and Exercisable		
Program	Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life
FE Plan	$19.31 - $29.87	1,040,749	$29.22	2.34
	$30.17 - $39.46	2,010,104	$37.63	3.67
GPU Plan	$23.75 - $35.92	16,347	$23.75	0.42
Total		3,067,200	$34.70	3.20

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 2009, and compensation expense in 2008 and 2007 was not material. Cash received from the exercise of stock options in 2009, 2008 and 2007 was $7 million, $74 million and $88 million, respectively.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock performance to a composite of peer companies. Compensation expense recognized for performance shares during 2009, 2008 and 2007, net of amounts capitalized, totaled approximately $3 million, $8 million and $20 million, respectively. Cash used to settle performance shares in 2009, 2008 and 2007 was $15 million, $14 million and $10 million, respectively.

(B) ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy's 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP. Between 1990 and 1991, the ESOP borrowed $200 million from OE and acquired 10,654,114 shares of OE's common stock (subsequently converted to FirstEnergy common stock) through market purchases. The ESOP loan was paid in full in 2008.

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 2009, 2008 and 2007, net of amounts capitalized and dividends on common stock, were $36 million, $40 million and $28 million, respectively.

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units or into an unfunded retirement cash account. An additional 20% premium is received in the form of stock units based on the amount allocated to the FirstEnergy stock account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Of the 1.3 million EDCP stock units authorized, 481,028 stock units were available for future awards as of December 31, 2009. Compensation expense (income) recognized on EDCP stock units, net of amounts capitalized, was not material in 2009, ($13) million in 2008 and $7 million in 2007, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. If the funds are deferred into the stock account, a 20% match is added to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control, or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. DCPD expenses recognized in each of 2009, 2008 and 2007 were approximately $3 million. The net liability recognized for DCPD of approximately $5 million as of December 31, 2009, 2008 and 2007 is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

(A) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are considered as short-term financial instruments and are reported on the Consolidated Balance Sheets at cost (which approximates their fair market value) under 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, 2009 and 2008:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$ 13,753	$ 14,502	$ 11,585	$ 11,146
FES	4,224	4,306	2,552	2,528
OE	1,169	1,299	1,232	1,223
CEI	1,873	2,032	1,741	1,618
TE	600	638	300	244
JCP&L	1,840	1,950	1,569	1,520
Met-Ed	842	909	542	519
Penelec	1,144	1,177	779	721

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 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 cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities as of December 31, 2009 and 2008:

	December 31, 2009[1]				December 31, 2008[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
Debt securities				(In millions)				
FirstEnergy[3]	$ 1,727	$ 22	$ -	$ 1,749	$ 1,078	$ 56	$ -	$ 1,134
FES	1,043	3	-	1,046	401	28	-	429
OE	55	-	-	55	86	9	-	95
TE	72	-	-	72	66	8	-	74
JCP&L	271	9	-	280	249	9	-	258
Met-Ed	120	5	-	125	111	4	-	115
Penelec	166	5	-	171	164	3	-	167
Equity securities								
FirstEnergy	$ 252	$ 43	$ -	$ 295	$ 589	$ 39	$ -	$ 628
FES	-	-	-	-	355	25	-	380
OE	-	-	-	-	17	1	-	18
JCP&L	74	11	-	85	64	2	-	66
Met-Ed	117	23	-	140	101	9	-	110
Penelec	61	9	-	70	51	2	-	53

(1) Excludes cash balances of $137 million at FirstEnergy, $43 million at FES, $3 million at JCP&L, $66 million at OE, $23 million at Penelec and $2 million at TE.
(2) Excludes cash balances of $244 million at FirstEnergy, $225 million at FES, $12 million at Penelec, $4 million at OE and $1 million at Met-Ed.
(3) Includes fair values as of December 31, 2009 and 2008 of $1,224 million and $953 million of government obligations, $523 million and $175 million of corporate debt and $1 million and $6 million of mortgage backed securities.

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 were as follows:

	FirstEnergy	FES	OE	TE	JCP&L	Met-Ed	Penelec
2009				(In millions)			
Proceeds from sales	$ 2,229	$ 1,379	$ 132	$ 169	$ 397	$ 68	$ 84
Realized gains	226	199	11	7	6	2	1
Realized losses	155	117	4	1	12	13	8
Interest and dividend income	60	27	4	2	14	7	6
2008							
Proceeds from sales	$ 1,657	$ 951	$ 121	$ 38	$ 248	$ 181	$ 118
Realized gains	115	99	11	1	1	2	1
Realized losses	237	184	9	-	17	17	10
Interest and dividend income	76	37	5	3	14	9	8
2007							
Proceeds from sales	$ 1,295	$ 656	$ 38	$ 45	$ 196	$ 185	$ 175
Realized gains	103	29	1	1	23	30	19
Realized losses	53	42	4	1	3	2	1
Interest and dividend income	80	42	4	3	13	8	10

Unrealized gains applicable to the decommissioning trusts of FES, OE and TE are recognized in OCI as 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 2009, 2008 and 2007, FirstEnergy recognized $176 million, $63 million and $10 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 (excluding emission allowances, employee benefits, and equity method investments of $264 million and $293 million that are not required to be disclosed) as December 31, 2009 and 2008:

	December 31, 2009				December 31, 2008			
Debt securities	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
FirstEnergy	$ 544	$ 72	$ -	$ 616	$ 673	$ 14	$ 13	$ 674
OE	217	29	-	246	240	-	13	227
CEI	389	43	-	432	426	9	-	435

Notes Receivable

The following table provides the approximate fair value and related carrying amounts of notes receivable as of December 31, 2009 and 2008:

	December 31, 2009		December 31, 2008	
Notes receivable	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$ 36	$ 35	$ 45	$ 44
FES	2	1	75	74
OE	-	-	257	294
TE	124	141	180	189

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 2010 to 2040.

(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 include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

Level 3 – Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the 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 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, 2009 and 2008. 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. During 2009, there were no significant transfers in or out of Level 1, Level 2, and Level 3.

Recurring Fair Value Measures as of December 31, 2009

(In millions)

	Level 1 – Assets				Level 1 - Liabilities		
	Derivatives	Available-for-Sale Securities[1]	Other Investments	Total	Derivatives	NUG Contracts[2]	Total
FirstEnergy	$ -	$ 294	$ -	$ 294	$ 11	$ -	$ 11
FES	-	-	-	-	11	-	11
OE	-	-	-	-	-	-	-
JCP&L	-	87	-	87	-	-	-
Met-Ed	-	133	-	133	-	-	-
Penelec	-	74	-	74	-	-	-

	Level 2 - Assets				Level 2 - Liabilities		
	Derivatives	Available-for-Sale Securities[1]	Other Investments	Total	Derivatives	NUG Contracts[2]	Total
FirstEnergy	$ 34	$ 1,864	$ 11	$ 1,909	$ 224	$ -	$ 224
FES	15	1,072	-	1,087	224	-	224
OE	-	120	-	120	-	-	-
TE	-	72	-	72	-	-	-
JCP&L	5	280	-	285	-	-	-
Met-Ed	9	134	-	143	-	-	-
Penelec	5	186	-	191	-	-	-

	Level 3 - Assets				Level 3 - Liabilities		
	Derivatives	Available-for-Sale Securities[1]	NUG Contracts[2]	Total	Derivatives	NUG Contracts[2]	Total
FirstEnergy	$ -	$ -	$ 200	$ 200	$ -	$ 643	$ 643
JCP&L	-	-	9	9	-	399	399
Met-Ed	-	-	176	176	-	143	143
Penelec	-	-	15	15	-	101	101

(1) Consists of investments in nuclear decommissioning trusts, spent nuclear fuel trusts and NUG trusts. Excludes $21 million of receivables, payables and accrued income.

(2) NUG contracts are subject to regulatory accounting and do not impact earnings.

Recurring Fair Value Measures as of December 31, 2008

(In millions)

	Level 1 – Assets				Level 1 - Liabilities		
	Derivatives	Available-for-Sale Securities[1]	Other Investments	Total	Derivatives	NUG Contracts[2]	Total
FirstEnergy	$ -	$ 537	$ -	$ 537	$ 25	$ -	$ 25
FES	-	290	-	290	25	-	25
OE	-	18	-	18	-	-	-
JCP&L	-	67	-	67	-	-	-
Met-Ed	-	104	-	104	-	-	-
Penelec	-	58	-	58	-	-	-

	Level 2 - Assets				Level 2 - Liabilities		
	Derivatives	Available-for-Sale Securities[1]	Other Investments	Total	Derivatives	NUG Contracts[2]	Total
FirstEnergy	$ 40	$ 1,464	$ 83	$ 1,587	$ 31	$ -	$ 31
FES	12	744	-	756	28	-	28
OE	-	98	-	98	-	-	-
TE	-	73	-	73	-	-	-
JCP&L	7	255	-	262	-	-	-
Met-Ed	14	121	-	135	-	-	-
Penelec	7	174	-	181	-	-	-

	Level 3 - Assets				Level 3 - Liabilities		
	Derivatives	Available-for-Sale Securities[1]	NUG Contracts[2]	Total	Derivatives	NUG Contracts[2]	Total
FirstEnergy	$ -	$ -	$ 434	$ 434	$ -	$ 766	$ 766
JCP&L	-	-	14	14	-	532	532
Met-Ed	-	-	300	300	-	150	150
Penelec	-	-	120	120	-	84	84

(1) Consists of investments in nuclear decommissioning trusts, spent nuclear fuel trusts and NUG trusts. Excludes $5 million of receivables, payables and accrued income.

(2) NUG contracts are subject to regulatory accounting and do not impact earnings.

The determination of the above 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 is a reconciliation of changes in the fair value of NUG contracts classified as Level 3 in the fair value hierarchy for 2009 and 2008 (in millions):

	FirstEnergy	JCP&L	Met-Ed	Penelec
Balance as of January 1, 2009	$ (332)	$ (518)	$ 150	$ 36
Settlements[1]	358	168	88	102
Purchases	-	-	-	-
Issuances	-	-	-	-
Sales	-	-	-	-
Unrealized losses[1]	(470)	(41)	(205)	(224)
Net transfers to Level 3	-	-	-	-
Net transfers from Level 3	-	-	-	-
Balance as of December 31, 2009	$ (444)	$ (391)	$ 33	$ (86)
Balance as of January 1, 2008	$ (803)	$ (750)	$ (28)	$ (25)
Settlements[1]	278	232	34	12
Unrealized gains[1]	193	-	144	49
Net transfers to (from) Level 3	-	-	-	-
Balance as of December 31, 2008	$ (332)	$ (518)	$ 150	$ 36

(1) Changes in fair value of NUG contracts are subject to regulatory accounting and do not impact earnings.

6. DERIVATIVE INSTRUMENTS

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

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchase and normal sales criteria. Derivatives that meet those criteria are accounted for at cost under the accrual method of accounting. The changes in the fair value of derivative instruments that do not meet the normal purchase and normal sales criteria are included in purchased power, other expense, unrealized gain (loss) on derivative hedges in other comprehensive income (loss), or as part of the value of the hedged item. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on its derivative instruments would not have had a material effect on FirstEnergy’s consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2009. Based on derivative contracts held as of December 31, 2009, an adverse 10% change in commodity prices would decrease net income by approximately $9 million during the next 12 months.

Interest Rate Risk

FirstEnergy uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Fixed-to-floating interest rate swaps are used, which are typically designated as fair value hedges, as a means to manage interest rate exposure. In addition, FirstEnergy uses interest rate derivatives to lock in interest rate levels in anticipation of future financings, which are typically designated as cash-flow hedges.

Cash Flow Hedges

Under the revolving credit facility (see Note 14), FirstEnergy and its subsidiaries, incur variable interest charges based on LIBOR. FirstEnergy currently holds a swap with a notional value of $100 million to hedge against changes in associated interest rates. This hedge will expire in January 2010 and is accounted for as a cash flow hedge. As of December 31, 2009, the fair value of the outstanding swap was immaterial.

FirstEnergy uses forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During 2009, FirstEnergy terminated forward swaps with a notional value of $2.8 billion and recognized losses of approximately $18.5 million; the ineffective portion recognized as an adjustment to interest expense was immaterial. The remaining effective portions will be amortized to interest expense over the life of the hedged debt.

Interest rate derivatives are included in "Other Noncurrent Liabilities" on FirstEnergy’s Consolidated Balance Sheets. The effects of interest rate derivatives on the Consolidated Statements of Income and Comprehensive Income during 2009 and 2008 were:

	December 31	
	2009	2008
	(In millions)	
Effective Portion		
Loss Recognized in AOCL	$ (18)	$ (44)
Loss Reclassified from AOCL into Interest Expense	(40)	(15)
Ineffective Portion		
Loss Recognized in Interest Expense	-	(7)

Total unamortized losses included in AOCL associated with prior interest rate hedges totaled $104 million ($62 million net of tax) as of December 31, 2009. Based on current estimates, approximately $11 million will be amortized to interest expense during the next twelve months. FirstEnergy's interest rate swaps do not include any contingent credit risk related features.

Fair Value Hedges

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

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting. Derivatives that do not qualify under the normal purchase or sales criteria or for hedge accounting as cash flow hedges are marked to market through earnings. FirstEnergy's risk policy does not allow derivatives to be used for speculative or trading purposes. FirstEnergy hedges forecasted electric sales and purchases and anticipated natural gas purchases using forwards and options. Heating oil futures are used to hedge oil purchases and fuel surcharges associated with rail transportation contracts. FirstEnergy's hedge term is typically two years. The effective portions of all cash flow hedges are initially recorded in AOCL and are subsequently included in net income as the underlying hedged commodities are delivered.

FirstEnergy discontinues hedge accounting prospectively when it is determined that a derivative is no longer effective in offsetting changes in the cash flows of a hedged item, in the case of forward-starting hedges, or when it is no longer probable that the forecasted transaction will occur. In 2009, FirstEnergy did not discontinue hedge accounting for any cash flow hedge items.

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

The following tables summarize the fair value of commodity derivatives in FirstEnergy's Consolidated Balance Sheets:

Derivative Assets	Fair Value December 31 2009	Fair Value December 31 2008	Derivative Liabilities	Fair Value December 31 2009	Fair Value December 31 2008
Cash Flow Hedges	*(In millions)*		Cash Flow Hedges	*(In millions)*	
Electricity Forwards			Electricity Forwards		
Current Assets	$ 3	$ 11	Current Liabilities	$ 7	$ 27
Noncurrent Assets	11	-	Noncurrent Assets	12	-
Natural Gas Futures			Natural Gas Futures		
Current Assets	-	-	Current Liabilities	9	4
Deferred Charges	-	-	Noncurrent Liabilities	-	5
Other			Other		
Current Assets	-	-	Current Liabilities	2	12
Deferred Charges	-	-	Noncurrent Liabilities	-	4
	$ 14	$ 11		$ 30	52

Derivative Assets	Fair Value December 31 2009	Fair Value December 31 2008	Derivative Liabilities	Fair Value December 31 2009	Fair Value December 31 2008
Economic Hedges	*(In millions)*		Economic Hedges	*(In millions)*	
NUG Contracts			NUG Contracts		
Power Purchase Contract Asset	$ 200	$ 434	Power Purchase Contract Liability	$ 643	$ 766
Other			Other		
Current Assets	-	1	Current Liabilities	106	1
Deferred Charges	19	28	Noncurrent Liabilities	97	-
	$ 219	$ 463		$ 846	$ 767
Total Commodity Derivatives	$ 233	$ 474	Total Commodity Derivatives	$ 876	$ 819

Electricity forwards are used to balance expected retail and wholesale sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas, primarily used in FirstEnergy's peaking units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy's coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs. The following table summarizes the volume of FirstEnergy's outstanding derivative transactions as of December 31, 2009.

	Purchases	Sales	Net	Units
		(In thousands)		
Electricity Forwards	11,684	(3,382)	8,302	MWH
Heating Oil Futures	4,620	-	4,620	Gallons
Natural Gas Futures	2,750	(2,250)	500	mmBtu

The effect of derivative instruments on the consolidated statements of income and comprehensive income (loss) for December 31, 2009 and 2008, for instruments designated in cash flow hedging relationships and not in hedging relationships, respectively, are summarized in the following tables:

Derivatives in Cash Flow Hedging Relationships	**Electricity Forwards**	**Natural Gas Futures**	**Heating Oil Futures**	**Total**
December 31, 2009		*(in millions)*		
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 7	$ (9)	$ 1	$ (1)
Effective Gain (Loss) Reclassified to:[1]				
Purchased Power Expense	(6)	-	-	(6)
Fuel Expense	-	(9)	(12)	(21)
December 31, 2008				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 3	$ (4)	$ (18)	$ (19)
Effective Gain (Loss) Reclassified to:[1]				
Purchased Power Expense	(6)	-	-	(6)
Fuel Expense	-	4	(2)	2

[1] The ineffective portion was immaterial.

Derivatives Not in Hedging Relationships	**NUG Contracts**	**Other**	**Total**
		(In millions)	
2009			
Unrealized Gain (Loss) Recognized in:			
Purchased Power Expense	$ -	$ (204)	$ (204)
Regulatory Assets[1]	(470)	-	(470)
	$ (470)	$ (204)	$ (674)
Realized Gain (Loss) Reclassified to:			
Regulatory Assets[1]	(348)	-	(348)
	$ (348)	$ -	$ (348)
2008			
Unrealized Gain (Loss) Recognized in:			
Fuel Expense[2]	$ -	$ 1	$ 1
Regulatory Assets[1]	193	2	195
	$ 193	$ 3	$ 196
Realized Gain (Loss) Reclassified to:			
Fuel Expense[2]	$ -	$ 1	$ 1
Regulatory Assets[1]	(267)	-	(267)
	$ (267)	$ 1	$ (266)

(1) Changes in the fair value of NUG contracts are deferred for future recovery from (or refund to) customers.

(2) The realized gain (loss) is reclassified upon termination of the derivative instrument.

Total unamortized losses included in AOCL associated with commodity derivatives were $15 million ($9 million net of tax) as of December 31, 2009, as compared to $44 million ($27 million net of tax) as of December 31, 2008. The net of tax change resulted from a $16 million decrease due to net hedge losses reclassified to earnings during 2009. Based on current estimates, approximately $9 million (after tax) of the net deferred losses on derivative instruments in AOCL as of December 31, 2009 are expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuate from period to period based on various market factors.

Many of FirstEnergy's commodity derivatives contain credit risk features. As of December 31, 2009, FirstEnergy posted $153 million of collateral related to net liability positions and held $26 million of counterparties' funds related to asset positions. The collateral FirstEnergy has posted relates to both derivative and non-derivative contracts. FirstEnergy's largest derivative counterparties fully collateralize all derivative transactions. Certain commodity derivative contracts include credit risk-related contingent features that would require FirstEnergy to post additional collateral if the credit rating for its debt were to fall below investment grade. The aggregate fair value of derivative instruments with credit risk-related contingent features that are in a liability position on December 31, 2009 was $220 million, for which $127 million in collateral has been posted. If FirstEnergy's credit rating were to fall below investment grade, it would be required to post $47 million of additional collateral related to commodity derivatives.

7. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity. The purchase price of approximately $1.329 billion (net after-tax proceeds of approximately $1.2 billion) for the undivided interest was funded through a combination of equity investments by affiliates of AIG Financial Products Corp. and Union Bank of California, N.A. in six lessor trusts and proceeds from the sale of $1.135 billion aggregate principal amount of 6.85% pass through certificates due 2034. A like principal amount of secured notes maturing June 1, 2034 were issued by the lessor trusts to the pass through trust that issued and sold the certificates. The lessor trusts leased the undivided interest back to FGCO for a term of approximately 33 years under substantially identical leases. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases. This transaction, which is classified as an operating lease for FES and FirstEnergy, generated tax capital gains of approximately $815 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowances in 2007, with a corresponding reduction to goodwill (see Note 2(E)).

Effective October 16, 2007 CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO and FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

During 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NGC purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

Rentals for capital and operating leases for the three years ended December 31, 2009 are summarized as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2009								
Operating leases	$ 236	$ 202	$ 146	$ 4	$ 64	$ 9	$ 7	$ 4
Capital leases								
Interest element	1	2	1	1	-	-	-	-
Other[(1)]	6	10	-	-	-	-	-	-
Total rentals	$ 243	$ 214	$ 147	$ 5	$ 64	$ 9	$ 7	$ 4
2008								
Operating leases	$ 381	$ 173	$ 146	$ 5	$ 65	$ 8	$ 4	$ 4
Capital leases								
Interest element	1	1	-	-	-	-	-	-
Other[(1)]	6	8	-	1	-	-	-	-
Total rentals	$ 388	$ 182	$ 146	$ 6	$ 65	$ 8	$ 4	$ 4
2007								
Operating leases	$ 376	$ 45	$ 145	$ 62	$ 101	$ 8	$ 4	$ 5
Capital leases								
Interest element	-	-	-	-	-	-	-	-
Other	1	-	-	1	-	-	-	-
Total rentals	$ 377	$ 45	$ 145	$ 63	$ 101	$ 8	$ 4	$ 5

(1) Includes $6 million and $5 million in 2009 and 2008, respectively, for wind purchased power agreements classified as capital leases.

The future minimum capital lease payments as of December 31, 2009 are as follows (TE, JCP&L, Met-Ed and Penelec have no material capital leases):

Capital Leases	FE	FES	OE	CEI
		(In millions)		
2010	$ 2	$ 6	$ -	$ 1
2011	2	6	-	1
2012	1	6	1	1
2013	1	6	-	1
2014	1	6	-	1
Years thereafter	3	18	-	3
Total minimum lease payments	10	48	1	8
Executory costs	-	-	-	-
Net minimum lease payments	10	48	1	8
Interest portion	6	6	-	6
Present value of net minimum lease payments	4	42	1	2
Less current portion	-	4	-	-
Noncurrent portion	$ 4	$ 38	$ 1	$ 2

The present value of minimum lease payments for FirstEnergy does not include $9 million of capital lease obligations that were prepaid at December 31, 2009.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 8).

The future minimum operating lease payments as of December 31, 2009 are as follows:

Operating Leases	FE Lease Payments	FE Capital Trusts	FE Net
		(In millions)	
2010	$ 341	$ 116	$ 225
2011	323	116	207
2012	360	125	235
2013	362	130	232
2014	358	131	227
Years thereafter	2,482	123	2,359
Total minimum lease payments	$ 4,226	$ 741	$ 3,485

Operating Leases	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
2010	$ 199	$ 146	$ 4	$ 64	$ 6	$ 7	$ 3
2011	190	146	3	64	5	4	3
2012	229	146	3	64	5	3	2
2013	235	145	3	64	5	3	2
2014	234	145	2	64	4	3	2
Years thereafter	2,133	305	5	140	49	35	20
Total minimum lease payments	$ 3,220	$ 1,033	$ 20	$ 460	$ 74	$ 55	$ 32

FirstEnergy recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The unamortized above-market lease liability for Beaver Valley Unit 2 of $236 million as of December 31, 2009, of which $37 million is classified as current, is being amortized by TE on a straight-line basis through the end of the lease term in 2017. The unamortized above-market lease liability for the Bruce Mansfield Plant of $308 million as of December 31, 2009, of which $46 million is classified as current, is being amortized by FGCO on a straight-line basis through the end of the lease term in 2016.

8. VARIABLE INTEREST ENTITIES

FirstEnergy and its subsidiaries consolidate VIEs when they are determined to be the VIE's primary beneficiary. FirstEnergy and its subsidiaries reflect the portion of VIEs not owned by them in the caption noncontrolling interest within the consolidated financial statements. The change in noncontrolling interest during 2009 is the result of net losses of the noncontrolling interests ($16 million), the acquisition of additional interest in certain joint ventures and other adjustments ($13 million), and distributions to owners ($5 million).

Mining Operations

On July 16, 2008, FEV entered into a joint venture with the Boich Companies, a Columbus, Ohio-based coal company, to acquire a majority stake in the Signal Peak mining and coal transportation operations near Roundup, Montana. FEV made a $125 million equity investment in the joint venture, which acquired 80% of the mining operations (Signal Peak Energy, LLC) and 100% of the transportation operations, with FEV owning a 45% economic interest and an affiliate of the Boich Companies owning a 55% economic interest in the joint venture. Both parties have a 50% voting interest in the joint venture. FEV consolidates the mining and transportation operations of this joint venture in its financial statements. In March 2009, FEV agreed to pay a total of $8.5 million to affiliates of the Boich Companies to purchase an additional 5% economic interest in the Signal Peak mining and coal transportation operations. Voting interests remained unchanged after the sale was completed in July 2009. Effective August 21, 2009, the joint venture acquired the remaining 20% stake in the mining operations by issuing a five-year note for $47.5 million. For both acquisitions, the difference between the consideration paid and the adjustment to the noncontrolling interest resulted in a charge to other paid in capital of approximately $30 million.

Trusts

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

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

Loss Contingencies

FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that render the applicable plant worthless. Net discounted lease payments would not be payable if the casualty loss payments are made. The following table shows each company’s net exposure to loss based upon the casualty value provisions mentioned above:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(in millions)	
FES	$ 1,348	$ 1,175	$ 173
OE	723	526	197
CEI	665	75	590
TE	665	382	283

(1) The net present value of FirstEnergy’s consolidated sale and leaseback operating lease commitments was $1.7 billion as of December 31, 2009 (see NGC lessor equity interest purchases described in Note 7).

See Note 7 for a discussion of CEI’s and TE’s assignment of their leasehold interests in the Bruce Mansfield Plant to FGCO.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Utilities and the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and Penelec, maintains 26 long-term power purchase agreements with NUG entities. The agreements were entered into pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

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

Since FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. Purchased power costs from these entities during 2009, 2008, and 2007 were $165 million, $178 million, and $176 million, respectively.

	2009	2008	2007
		(In millions)	
JCP&L	$ 73	$ 84	$ 90
Met-Ed	57	61	56
Penelec	35	33	30
Total	$ 165	$ 178	$ 176

9. DIVESTITURES

On March 7, 2008, FirstEnergy sold certain telecommunication assets, resulting in a net after-tax gain of $19.3 million. The sale of assets did not meet the criteria for classification as discontinued operations as of December 31, 2008.

10. TAXES

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2009 are shown below:

PROVISION FOR INCOME TAXES	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2009								
Currently payable-								
Federal	$ (183)	$ 87	$ 21	$ 40	$ 6	$ 40	$ (34)	$ (21)
State	44	8	4	2	-	26	(4)	4
	(139)	95	25	42	6	66	(38)	(17)
Deferred, net-								
Federal	351	200	40	(52)	-	41	60	60
State	42	24	3	1	2	2	7	4
	393	224	43	(51)	2	43	67	64
Investment tax credit amortization	(9)	(4)	(2)	(1)	-	-	-	(1)
Total provision for income taxes	$ 245	$ 315	$ 66	$ (10)	$ 8	$ 109	$ 29	$ 46
2008								
Currently payable-								
Federal	$ 355	$ 156	$ 79	$ 119	$ 46	$ 101	$ 5	$ (34)
State	56	20	4	6	-	34	6	(3)
	411	176	83	125	46	135	11	(37)
Deferred, net-								
Federal	343	109	22	16	(12)	9	47	84
State	36	12	(2)	(2)	(4)	4	4	12
	379	121	20	14	(16)	13	51	96
Investment tax credit amortization	(13)	(4)	(4)	(2)	-	-	(1)	(1)
Total provision for income taxes	$ 777	$ 293	$ 99	$ 137	$ 30	$ 148	$ 61	$ 58
2007								
Currently payable-								
Federal	$ 706	$ 528	$ 105	$ 166	$ 73	$ 138	$ 26	$ 41
State	187	111	(4)	20	7	42	7	12
	893	639	101	186	80	180	33	53
Deferred, net-								
Federal	22	(288)	-	(23)	(27)	(25)	30	10
State	(18)	(42)	4	2	2	(5)	6	1
	4	(330)	4	(21)	(25)	(30)	36	11
Investment tax credit amortization	(14)	(4)	(4)	(2)	(1)	(1)	(1)	-
Total provision for income taxes	$ 883	$ 305	$ 101	$ 163	$ 54	$ 149	$ 68	$ 64

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31, 2009.

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2009								
Book income before provision for income taxes	$ 1,251	$ 892	$ 188	$ (23)	$ 32	$ 279	$ 84	$ 111
Federal income tax expense at statutory rate	$ 438	$ 312	$ 66	$ (8)	$ 11	$ 98	$ 29	$ 39
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(9)	(4)	(2)	(1)	-	-	-	(1)
State income taxes, net of federal tax benefit	56	21	5	2	1	18	2	5
Manufacturing deduction	(13)	(11)	(2)	1	(1)	-	-	-
Effectively settled tax items	(217)	-	-	-	-	-	-	-
Other, net	(10)	(3)	(1)	(4)	(3)	(7)	(2)	3
Total provision for income taxes	$ 245	$ 315	$ 66	$ (10)	$ 8	$ 109	$ 29	$ 46
2008								
Book income before provision for income taxes	$ 2,119	$ 800	$ 310	$ 421	$ 105	$ 335	$ 149	$ 146
Federal income tax expense at statutory rate	$ 742	$ 280	$ 109	$ 147	$ 37	$ 117	$ 52	$ 51
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(13)	(4)	(4)	(2)	-	-	(1)	(1)
State income taxes, net of federal tax benefit	60	21	1	2	(2)	25	7	5
Manufacturing deduction	(29)	(16)	(3)	(8)	(2)	-	-	-
Effectively settled tax items	(14)	-	-	-	-	-	-	-
Other, net	31	12	(4)	(2)	(3)	6	3	3
Total provision for income taxes	$ 777	$ 293	$ 99	$ 137	$ 30	$ 148	$ 61	$ 58
2007								
Book income before provision for income taxes	$ 2,192	$ 833	$ 298	$ 440	$ 145	$ 335	$ 164	$ 157
Federal income tax expense at statutory rate	$ 767	$ 292	$ 104	$ 154	$ 51	$ 117	$ 57	$ 55
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(14)	(4)	(4)	(2)	(1)	(1)	(1)	-
State income taxes, net of federal tax benefit	110	45	-	14	6	24	9	8
Manufacturing deduction	(9)	(6)	(2)	(1)	-	-	-	-
Other, net	29	(22)	3	(2)	(2)	9	3	1
Total provision for income taxes	$ 883	$ 305	$ 101	$ 163	$ 54	$ 149	$ 68	$ 64

Accumulated deferred income taxes as of December 31, 2009 and 2008 are as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
AS OF DECEMBER 31, 2009								
Property basis differences	$ 3,049	$ 619	$ 508	$ 419	$ 177	$ 458	$ 275	$ 350
Regulatory transition charge	334	-	67	95	2	157	13	-
Customer receivables for future income taxes	111	-	-	-	-	13	49	49
Deferred customer shopping incentive	55	-	-	55	-	-	-	-
Deferred MISO/PJM transmission costs	89	-	-	-	-	-	90	(1)
Other regulatory assets - RCP	162	-	80	54	28			-
Deferred sale and leaseback gain	(486)	(426)	(40)	-	-	(9)	(11)	-
Nonutility generation costs	9	-	-	-	-	-	48	(39)
Unamortized investment tax credits	(48)	(22)	(4)	(4)	(2)	(2)	(5)	(4)
Unrealized losses on derivative hedges	(44)	(8)	-	-	-	(1)	(1)	-
Pension and other postretirement obligations	(611)	(75)	(57)	(18)	(34)	(72)	(20)	(83)
Lease market valuation liability	(232)	(101)	-	-	(111)	-	-	-
Oyster Creek securitization (Note 12(C))	132	-	-	-	-	132	-	-
Nuclear decommissioning activities	(34)	23	5	-	12	(19)	(1)	(52)
Mark-to-market adjustments	(76)	(76)	-	-	-	-	-	-
Deferred gain for asset sales - affiliated companies	-	-	37	25	8	-	-	-
Allowance for equity funds used used during construction	15	-	15	-	-	-	-	-
Loss carryforwards	(33)	-	-	-	-	-	-	-
Loss carryforward valuation reserve	21	-	-	-	-	-	-	-
All other	55	(21)	49	19	1	31	16	22
Net deferred income tax liability (asset)	$ 2,468	$ (87)	$ 660	$ 645	$ 81	$ 688	$ 453	$ 242
AS OF DECEMBER 31, 2008								
Property basis differences	$ 2,736	$ 434	$ 494	$ 428	$ 172	$ 436	$ 275	$ 329
Regulatory transition charge	292	-	40	29	4	190	29	-
Customer receivables for future income taxes	145	-	22	1	-	24	49	48
Deferred customer shopping incentive	151	-	-	151	-	-	-	-
Deferred MISO/PJM transmission costs	167	-	11	7	7	-	137	4
Other regulatory assets - RCP	253	-	121	100	32	-	-	-
Deferred sale and leaseback gain	(505)	(438)	(45)	-	-	(10)	(12)	-
Nonutility generation costs	(52)	-	-	-	-	-	30	(82)
Unamortized investment tax credits	(51)	(23)	(5)	(5)	(2)	(2)	(6)	(5)
Unrealized losses on derivative hedges	(68)	(15)	-	-	-	(1)	(1)	-
Pension and other postretirement obligations	(715)	(68)	(94)	(47)	(25)	(90)	(72)	(89)
Lease market valuation liability	(254)	(124)	-	-	(122)	-	-	-
Oyster Creek securitization (Note 12(C))	137	-	-	-	-	137	-	-
Nuclear decommissioning activities	(130)	14	2	-	13	(34)	(65)	(55)
Deferred gain for asset sales - affiliated companies	-	-	41	27	9	-	-	-
Allowance for equity funds used during construction	21	-	20	1	-	-	-	-
Loss carryforwards	(35)	-	-	-	-	-	-	-
Loss carryforward valuation reserve	27	-	-	-	-	-	-	-
All other	44	(48)	46	12	(9)	39	24	20
Net deferred income tax liability (asset)	$ 2,163	$ (268)	$ 653	$ 704	$ 79	$ 689	$ 388	$ 170

Upon reaching a settlement on several items under appeal for the tax years 2001-2003, as well as other items that effectively settled in 2009, FirstEnergy recognized approximately $100 million of net tax benefits, including $161 million that favorably affected FirstEnergy's effective tax rate. The offsetting $61 million primarily related to tax items where the uncertainty was removed and the tax refund will be received when the tax years are closed. Upon completion of the federal tax examinations for tax years 2004-2006, as well as other tax settlements reached in 2008, FirstEnergy recognized approximately $42 million of net tax benefits, including $7 million that favorably affected FirstEnergy's effective tax rate. The remaining balance of the tax benefits recognized in 2008 adjusted goodwill as a purchase price adjustment ($20 million) and accumulated deferred income taxes for temporary tax items ($15 million). During 2007, there were no material changes to FirstEnergy's unrecognized tax benefits.

As of December 31, 2009, it is reasonably possible that approximately $148 million of the unrecognized benefits may be resolved within the next twelve months, of which up to approximately $11 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to the capitalization of certain costs and various state tax items.

In 2008, FirstEnergy, on behalf of FGCO and NGC, filed a change in accounting method related to the costs to repair and maintain electric generation stations. During the second quarter of 2009, the IRS approved the change in accounting method and $281 million of costs were included as a repair deduction on FirstEnergy's 2008 consolidated tax return. Since the IRS did not complete its review over this change in accounting method by the extended filing date of FirstEnergy's federal tax return, FirstEnergy increased the amount of unrecognized tax benefits by $34 million in the third quarter of 2009, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item. There was no impact on FirstEnergy's effective tax rate for the year.

In 2009, FirstEnergy, on behalf of OE, PP, CEI, TE, ATSI, JCP&L, Met-Ed and Penelec, filed a change in accounting method related to the costs to repair and maintain electric utility network (transmission and distribution) assets and is in the process of computing the amount of costs that will qualify as a deduction to be included on FirstEnergy's 2009 consolidated tax return. This change in accounting method is expected to have a material impact on taxable income for 2009 and could increase the amount of tax refunds to be recognized in 2010 with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item. There would be no impact on FirstEnergy's effective tax rate.

The changes in unrecognized tax benefits for the three years ended December 31, 2009 are as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Balance as of January 1, 2009	$ 219	$ 5	$ (30)	$ (26)	$ (4)	$ 42	$ 28	$ 24
Increase for tax positions related to the current year	41	34	4	3	-	-	-	-
Increase for tax positions related to prior years	46	2	103	52	10	-	-	-
Decrease for tax positions related to prior years	(100)	-	-	-	-	(28)	(15)	(13)
Decrease for settlement	(15)	-	-	-	-	-	-	-
Balance as of December 31, 2009	$ 191	$ 41	$ 77	$ 29	$ 6	$ 14	$ 13	$ 11

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Balance as of January 1, 2008	$ 272	$ 14	$ (12)	$ (17)	$ (1)	$ 38	$ 24	$ 16
Increase for tax positions related to the current year	14	-	1	-	-	-	-	-
Increase for tax positions related to prior years	-	1	1	-	-	6	5	9
Decrease for tax positions related to prior years	(56)	(10)	(14)	(8)	(3)	(2)	(1)	(1)
Decrease for settlement	(11)	-	(6)	(1)	-	-	-	-
Balance as of December 31, 2008	$ 219	$ 5	$ (30)	$ (26)	$ (4)	$ 42	$ 28	$ 24

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Balance as of January 1, 2007	$ 268	$ 14	$ (19)	$ (15)	$ (3)	$ 44	$ 18	$ 20
Increase for tax positions related to the current year	1	-	1	-	-	-	-	-
Increase for tax positions related to prior years	3	4	10	2	2	-	6	-
Decrease for tax positions related to prior years	-	(4)	(4)	(4)	-	(6)	-	(4)
Balance as of December 31, 2007	$ 272	$ 14	$ (12)	$ (17)	$ (1)	$ 38	$ 24	$ 16

FirstEnergy 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. The reversal of accrued interest associated with the $161 million in recognized tax benefits favorably affected FirstEnergy's effective tax rate in 2009 by $56 million and an interest receivable of $11 million was removed from the accrued interest for uncertain tax positions. The reversal of accrued interest associated with the $56 million in recognized tax benefits favorably affected FirstEnergy's effective tax rate in 2008 by $12 million and an interest receivable of $4 million was removed from the accrued interest for uncertain tax positions. During the years ended December 31, 2009, 2008 and 2007, FirstEnergy recognized net interest expense (income) of approximately $(49) million, $2 million and $19 million, respectively. The net amount of interest accrued as of December 31, 2009 and 2008 was $21 million and $59 million, respectively.

The following table summarizes the net interest expense (income) recognized by FES and the Utilities for the three years ended December 31, 2009 and the cumulative net interest payable (receivable) as of December 31, 2009 and 2008:

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable (Receivable) As of December 31,	
	2009	2008	2007	2009	2008
		(In millions)		*(In millions)*	
FES	$ (1)	$ -	$ -	$ 2	$ 1
OE	4	(4)	1	9	(9)
CEI	3	(2)	(1)	3	(7)
TE	-	-	-	1	(1)
JCP&L	(4)	1	1	1	11
Met-Ed	(2)	1	2	1	6
Penelec	(1)	2	-	1	6

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state tax authorities. All state jurisdictions are open from 2001-2008. The IRS began reviewing returns for the years 2001-2003 in July 2004 and several items were under appeal. In the fourth quarter of 2009, these items were settled at appeals and sent to Joint Committee on Taxation for final review. The federal audits for years 2004-2006 were completed in the third quarter of 2008 and several items are under appeal. The IRS began auditing the year 2007 in February 2007 under its Compliance Assurance Process program and was completed in the first quarter of 2009 with two items under appeal. The IRS began auditing the year 2008 in February 2008 and the audit is expected to close before December 2010. The 2009 tax year audit began in February 2009 and is not expected to close before December 2010. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy's financial condition or results of operations.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity (see Note 7). This transaction generated tax capital gains of approximately $815 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowance in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $1.044 billion, of which $194 million is expected to be utilized. The associated deferred tax assets are $11 million. These losses expire as follows:

Expiration Period	FE	FES	Penelec
		(In millions)	
2010-2014	$ 226	$ 16	$ -
2015-2019	8	-	-
2020-2024	523	23	200
2025-2028	287	65	-
	$ 1,044	$ 104	$ 200

General Taxes

Details of general taxes for the three years ended December 31, 2009 are shown below:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2009								
Kilowatt-hour excise(1)	$ 224	$ 1	$ 84	$ 66	$ 24	$ 49	$ -	$ -
State gross receipts	171	14	15	-	-	-	78	63
Real and personal property	253	53	64	74	21	5	2	2
Social security and unemployment	90	14	8	5	3	9	5	6
Other	15	5	-	-	-	-	3	3
Total general taxes	$ 753	$ 87	$ 171	$ 145	$ 48	$ 63	$ 88	$ 74
2008								
Kilowatt-hour excise	$ 249	$ 1	$ 97	$ 70	$ 30	$ 51	$ -	$ -
State gross receipts	183	16	17	-	-	-	79	70
Real and personal property	240	53	61	67	19	5	3	2
Social security and unemployment	95	14	9	6	3	10	5	6
Other	11	4	2	-	-	1	(1)	2
Total general taxes	$ 778	$ 88	$ 186	$ 143	$ 52	$ 67	$ 86	$ 80
2007								
Kilowatt-hour excise	$ 250	$ 1	$ 99	$ 69	$ 29	$ 52	$ -	$ -
State gross receipts	175	18	17	-	-	-	73	66
Real and personal property	237	53	59	65	19	5	2	2
Social security and unemployment	87	14	8	6	3	9	5	5
Other	5	1	(2)	2	-	-	-	3
Total general taxes	$ 754	$ 87	$ 181	$ 142	$ 51	$ 66	$ 80	$ 76

(1) Kilowatt-hour excise tax for OE and TE includes a $7.1 million and $3.5 million adjustment, respectively, recognized in 2009 related to prior periods.

11. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

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

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

In April 2007, ReliabilityFirst performed a routine compliance audit of FirstEnergy's bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, ReliabilityFirst performed a routine compliance audit of FirstEnergy's bulk-power system within the PJM region and found it to be in full compliance with all audited reliability standards . Our MISO facilities are next due for the periodic audit by Reliability*First* later this year.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. The initial phase of the investigation required JCP&L to respond to the NERC's request for factual data about the outage. JCP&L submitted its written response on May 1, 2009. The NERC conducted on site interviews with personnel involved in responding to the event on June 16-17, 2009. On July 7, 2009, the NERC issued additional questions regarding the event and JCP&L replied as requested on August 6, 2009. JCP&L is not able at this time to predict what actions, if any, that the NERC may take based on the data submittals or interview results.

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

(B) OHIO

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing. On January 21, 2009, the PUCO granted the Ohio Companies' application in part to increase electric distribution rates by $136.6 million (OE - $68.9 million, CEI - $29.2 million and TE - $38.5 million). These increases went into effect for OE and TE on January 23, 2009, and for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009. The PUCO granted these applications for rehearing on March 18, 2009 for the purpose of further consideration. The PUCO has not yet issued a substantive Entry on Rehearing.

SB221, which became effective on July 31, 2008, required all electric utilities to file an ESP, and permitted the filing of an MRO. On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and a separate MRO. The PUCO denied the MRO application; however, the PUCO later granted the Ohio Companies' application for rehearing for the purpose of further consideration of the matter. The PUCO has not yet issued a substantive Entry on Rehearing. The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. In response to the PUCO's December 19, 2008 order, which significantly modified and approved the ESP as modified, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application in addition to continuing their rate plan then in effect as allowed by the terms of SB221. On December 31, 2008, the Ohio Companies conducted a CBP for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. The average winning bid price was equivalent to a retail rate of 6.98 cents per KWH. The power supply obtained through this process provided generation service to the Ohio Companies' retail customers who chose not to shop with alternative suppliers. On January 9, 2009, the Ohio Companies requested the implementation of a new fuel rider to recover the costs resulting from the December 31, 2008 CBP. The PUCO ultimately approved the Ohio Companies' request for a new fuel rider to recover increased costs resulting from the CBP but denied OE's and TE's request to continue collecting RTC and denied the request to allow the Ohio Companies to continue collections pursuant to the two existing fuel riders. The new fuel rider recovered the increased purchased power costs for OE and TE, and recovered a portion of those costs for CEI, with the remainder being deferred for future recovery.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies. On February 19, 2009, the Ohio Companies filed an Amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties. Specifically, the Amended ESP provided that generation would be provided by FES at the average wholesale rate of the CBP process described above for April and May 2009 to the Ohio Companies for their non-shopping customers; for the period of June 1, 2009 through May 31, 2011, retail generation prices would be based upon the outcome of a descending clock CBP on a slice-of-system basis. The Amended ESP further provided that the Ohio Companies will not seek a base distribution rate increase, subject to certain exceptions, with an effective date of such increase before January 1, 2012, that CEI would agree to write-off approximately $216 million of its Extended RTC regulatory asset, and that the Ohio Companies would collect a delivery service improvement rider at an overall average rate of $.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Amended ESP also addressed a number of other issues, including but not limited to, rate design for various customer classes, and resolution of the prudence review and the collection of deferred costs that were approved in prior proceedings. On February 26, 2009, the Ohio Companies filed a Supplemental Stipulation, which was signed or not opposed by virtually all of the parties to the proceeding, that supplemented and modified certain provisions of the February 19, 2009 Stipulation and Recommendation. Specifically, the Supplemental Stipulation modified the provision relating to governmental aggregation and the Generation Service Uncollectible Rider, provided further detail on the allocation of the economic development funding contained in the Stipulation and Recommendation, and proposed additional provisions related to the collaborative process for the development of energy efficiency programs, among other provisions. The PUCO adopted and approved certain aspects of the Stipulation and Recommendation on March 4, 2009, and adopted and approved the remainder of the Stipulation and Recommendation and Supplemental Stipulation without modification on March 25, 2009. Certain aspects of the Stipulation and Recommendation and Supplemental Stipulation took effect on April 1, 2009 while the remaining provisions took effect on June 1, 2009.

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

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

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

In October 2009, the PUCO issued additional Entries on Rehearing, modifying certain of its previous rules that set out the manner in which electric utilities, including the Ohio Companies, will be required to comply with benchmarks contained in SB221 related to the employment of alternative energy resources, energy efficiency/peak demand reduction programs as well as greenhouse gas reporting requirements and changes to long term forecast reporting requirements. Applications for rehearing filed in mid-November 2009 were granted on December 9, 2009 for the sole purpose of further consideration of the matters raised in those applications. The PUCO has not yet issued a substantive Entry on Rehearing. The rules implementing the requirements of SB221 went into effect on December 10, 2009. The rules set out the manner in which electric utilities, including the Ohio Companies, will be required to comply with benchmarks contained in SB221 related to the employment of alternative energy resources, energy efficiency/peak demand reduction programs as well as greenhouse gas reporting requirements and carbon dioxide control planning requirements and changes to long term forecast reporting requirements. The rules severely restrict the types of renewable energy resources energy efficiency and peak reduction programs that may be included toward meeting the statutory goals, which is expected to increase the cost of compliance for the Ohio Companies' customers. As a result of the rules going into effect in December 2009, and the PUCO's failure to address certain energy efficiency applications submitted by the Ohio Companies throughout the year and the PUCO's directive to postpone the launch of a PUCO-approved energy efficiency program, the Ohio Companies, on October 27, 2009, submitted an application to amend their 2009 statutory energy efficiency benchmarks to zero. On January 7, 2010, the PUCO issued an Order granting the Companies' request to amend the energy efficiency benchmarks.

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

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

(C) PENNSYLVANIA

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations.

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

On May 22, 2008, the PPUC approved Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. The TSCs included a component for under-recovery of actual transmission costs incurred during the prior period (Met-Ed - $144 million and Penelec - $4 million) and transmission cost projections for June 2008 through May 2009 (Met-Ed - $258 million and Penelec - $92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs ($92 million) plus carrying charges for recovery through future TSCs by December 31, 2010. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both Met-Ed and Penelec have concluded. On August 11, 2009, the ALJ issued a Recommended Decision to the PPUC approving Met-Ed's and Penelec's TSCs as filed and dismissing all complaints. Exceptions by various interveners were filed and reply exceptions were filed by Met-Ed and Penelec. On January 28, 2010, the PPUC adopted a motion which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, and instructs Met-Ed and Penelec to work with the parties and file a petition to retain any over-collection, with interest, until 2011 for the purpose of providing mitigation of future rate increases starting in 2011 for their customers. Met-Ed and Penelec are now awaiting an order, which is expected to be consistent with the motion. If so, Met-Ed and Penelec plan to appeal such a decision to the Commonwealth Court of Pennsylvania. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of the companies that they should prevail in any such appeal and therefore expect to fully recover the approximately $170.5 million ($138.7 million for Met-Ed and $31.8 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

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

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

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

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

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

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

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

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

(D) NEW JERSEY

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 30, 2009, the accumulated deferred cost balance totaled approximately $98 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. TMI-2 is a retired nuclear facility owned by JCP&L. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DPA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to those comments. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set. On March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009. This matter is currently pending before the NJBPU.

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

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

- maximize energy efficiency to achieve a 20% reduction in energy consumption by 2020;

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

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

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

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

(E) FERC MATTERS

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or SECA) during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. A final order is pending before the FERC, and in the meantime, FirstEnergy affiliates have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements. On October 29, 2009, FirstEnergy, with another Company, filed an additional settlement agreement with FERC to resolve their outstanding claims. FirstEnergy is actively pursuing settlement agreements with other parties to the case. On December 8, 2009, certain parties sought a writ of mandamus from the DC Circuit Court of Appeals directing FERC to issue an order on the Initial Decision. The Court agreed to hold this matter in abeyance based upon FERC's representation to use good faith efforts to issue a substantive ruling on the initial decision no later than May 27, 2010. If FERC fails to act, the case will be submitted for briefing in June. This matter is pending in the Court and the outcome cannot be predicted.

PJM Transmission Rate

On January 31, 2005, certain PJM transmission owners made filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design, notably AEP, which proposed to create a "postage stamp," or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. AEP's proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order (Opinion 494) finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, the FERC's April 19, 2007, and January 31, 2008, orders were appealed to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and another party have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others have been consolidated for argument in the Seventh Circuit. The Seventh Circuit Court of Appeals issued a decision on August 6, 2009, that remanded the rate design to FERC and denied the appeal. A request for rehearing and rehearing en banc by two Companies was denied by the Seventh Circuit on October 20, 2009. On October 28, 2009, the Seventh Circuit closed its case dockets and returned the case to FERC for further action on the remand order. In an order dated January 21, 2010, FERC set the matter for "paper hearings" – meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments, and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments on April 8, 2010 and May 10, 2010.

The FERC's orders on PJM rate design prevented the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis reduces the cost of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement. On November 14, 2008, PJM submitted revisions to its tariff to incorporate cost responsibility assignments for below 500 kV upgrades included in PJM's Regional Transmission Expansion Planning process in accordance with the settlement. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. On November 19, 2009, FERC issued Opinion 503 agreeing that RTEP costs should be allocated on a pro-rata basis to merchant transmission companies. On December 22, 2009, a request for a rehearing of FERC's Opinion No. 503 was made. On January 19, 2010, FERC issued a procedural order noting that FERC would address the rehearing requests in a future order.

RTO Consolidation

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

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

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

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

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

FirstEnergy will conduct FRR auctions on March 15-19, 2010, for the 2011-12 and 2012-13 delivery years, and will participate in PJM's next base residual auction for capacity resources for the 2013-2014 delivery years. FirstEnergy expects to integrate into PJM effective June 1, 2011.

Changes ordered for PJM Reliability Pricing Model (RPM) Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, FirstEnergy and other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement discussions. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement, which used the PJM December 12, 2008 filing as its starting point, and stated that unless otherwise specified, provisions filed by PJM on December 12, 2008 apply.

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

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

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn and FES. This requirement was proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. FirstEnergy believes the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including FirstEnergy, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On April 16, 2009, the FERC issued an additional order on rehearing and compliance, approving MISO's proposed financial settlement provision for Resource Adequacy. The MISO Resource Adequacy program was implemented as planned and became effective on June 1, 2009, the beginning of the MISO planning year. On June 17, 2009, MISO submitted a compliance filing in response to the FERC's April 16, 2009 order directing it to address, among others, various market monitoring and mitigation issues. On July 8, 2009, various parties submitted comments on and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific aspects of the MISO's and Independent Market Monitor's proposals for market monitoring and mitigation and other issues that it believes the FERC should address and clarify. On October 23, 2009, FERC issued an order approving a MISO compliance filing that revised its tariff to provide for netting of demand resources, but prohibiting the netting of behind-the-meter generation.

FES Sales to Affiliates

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

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

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

12. CAPITALIZATION

(A) COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2009, FirstEnergy's unrestricted retained earnings were $4.5 billion. Dividends declared in 2009 were $2.20, which included four quarterly dividends of $0.55 per share paid in the second, third and fourth quarters of 2009 and payable in the first quarter of 2010. Dividends declared in 2008 were $2.20, which included four quarterly dividends of $0.55 per share paid in the second, third and fourth quarters of 2008 and first quarter of 2009. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, each of FirstEnergy's electric utility subsidiaries has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. The articles of incorporation, indentures and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' ability to pay cash dividends to FirstEnergy as of December 31, 2009.

(B) PREFERRED AND PREFERENCE STOCK

FirstEnergy's and the Utilities' preferred stock and preference stock authorizations are as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$100		
OE	6,000,000	$100	8,000,000	no par
OE	8,000,000	$25		
Penn	1,200,000	$100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$100	5,000,000	$25
TE	12,000,000	$25		
JCP&L	15,600,000	no par		
Met-Ed	10,000,000	no par		
Penelec	11,435,000	no par		

No preferred shares or preference shares are currently outstanding.

(C) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following table presents the outstanding consolidated long-term debt and other long-term obligations of FirstEnergy as of December 31, 2009 and 2008:

	Weighted Average Interest Rate (%)	December 31, 2009	December 31, 2008
		(In millions)	
FMBs:			
Due 2009-2013	5.96	$ 28	$ 29
Due 2014-2018	8.84	330	330
Due 2019-2023	6.22	107	7
Due 2024-2028	8.75	314	14
Due 2038	8.25	275	275
Total FMBs		1,054	655
Secured Notes:			
Due 2009-2013	7.68	356	607
Due 2014-2018	7.35	557	613
Due 2019-2023	7.05	341	70
Total Secured Notes		1,254	1,290
Unsecured Notes:			
Due 2009-2013	5.50	878	2,253
Due 2014-2018	5.56	2,693	2,149
Due 2019-2023	5.47	2,575	689
Due 2024-2028	4.36	65	65
Due 2029-2033	6.18	2,247	2,247
Due 2034-2038	4.99	2,186	1,936
Due 2039-2043	4.70	755	255
Due 2047	3.00	46	46
Total Unsecured Notes		11,445	9,640
Capital lease obligations		13	8
Net unamortized discount on debt		(24)	(17)
Long-term debt due within one year		(1,834)	(2,476)
Total long-term debt and other long-term obligations		$ 11,908	$ 9,100

Securitized Transition Bonds

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

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. As of December 31, 2009, $340 million of the transition bonds were outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company’s equity and assets, which consist primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to $628,000 that are payable from TBC collections.

Other Long-term Debt

FGCO, NGC and each of the Utilities, except for JCP&L, have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

FirstEnergy and its subsidiaries have various debt covenants under their respective financing arrangements. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios. There also exist cross-default provisions in a number of the respective financing arrangements of FirstEnergy, FES, FGCO, NGC and the Utilities. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries defaults under another financing arrangement of a certain principal amount, typically $50 million. Although such defaults by any of the Utilities will generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by FirstEnergy will not generally cross-default applicable financing arrangements of any of the Utilities. Defaults by any of FES, FGCO or NGC will generally cross-default to applicable financing arrangements of FirstEnergy and, due to the existence of guarantees by FirstEnergy of certain financing arrangements of FES, FGCO and NGC, defaults by FirstEnergy will generally cross-default FES, FGCO and NGC financing arrangements containing these provisions. Cross-default provisions are not typically found in any of the senior note or FMBs of FirstEnergy or the Utilities.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees through December 31, 2009, the Utilities’ annual sinking fund requirement for all FMB issued under the various mortgage indentures amounted to $35 million (Penn - $6 million, Met-Ed - $8 million and Penelec - $21 million). Penn expects to meet its 2010 annual sinking fund requirement with a replacement credit under its mortgage indenture. Met-Ed and Penelec could fulfill their sinking fund obligations by providing bondable property additions, previously retired FMBs or cash to the respective mortgage bond trustees.

As of December 31, 2009, FirstEnergy’s currently payable long-term debt includes approximately $1.6 billion (FES - $1.5 billion, Met-Ed - $29 million and Penelec - $45 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. Prior to the third quarter of 2008, FirstEnergy subsidiaries had not experienced any unsuccessful remarketings of these variable-rate PCRBs. Coincident with recent disruptions in the variable-rate demand bond and capital markets generally, certain of the PCRBs had been tendered by bondholders to the trustee. As of January 31, 2009, all PCRBs that had been tendered were successfully remarketed.

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

Sinking fund requirements for FMBs and maturing long-term debt (excluding capital leases and variable rate PCRBs) for the next five years are:

Year	FE	FES	OE	CEI	JCP&L	Met-Ed	Penelec
				(In millions)			
2010	268	52	2	18	31	100	24
2011	337	58	1	20	32	-	-
2012	99	68	1	22	34	-	-
2013	557	75	2	324	36	150	-
2014	531	99	1	26	38	250	150

The following table classifies the outstanding PCRBs by year, for the next three years, representing the next time the debt holders may exercise their right to tender their PCRBs.

Year	FE	FES	Met-Ed	Penelec
		(In millions)		
2010	1,568	1,494	29	45
2011	75	75	-	-
2012	244	244	-	-

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs of $1.6 billion as of December 31, 2009, or noncancelable municipal bond insurance of $38 million as of December 31, 2009, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs or the insurance, FGCO, NGC and the Utilities are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Utilities pay annual fees of 0.35% to 3.30% of the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations. These amounts and percentages for FirstEnergy, FES and the Utilities are as follows:

	FE	FES	Met-Ed	Penelec
		(In millions)		
Amounts				
LOCs	$ 1,568	$ 1,494*	$ 29	$ 45
Insurance Policies	38	-	14	24
Fees				
LOCs	0.35% to 3.30%	0.35% to 3.30%	1.5%	1.5%

* Includes LOC of $137 million issued for FirstEnergy on behalf of NGC.

OE has LOCs of $200 million and $134 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. In 2004, OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of approximately $236 million of the Beaver Valley Unit 2 LOCs and the issuer of the standby LOC obtained the right to pledge or assign participations in OE's reimbursement obligations under the credit agreement to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE. In 2009, these LOCs were renewed in the amount of $145 million.

13. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two coal ash disposal sites. In addition, FirstEnergy has recognized conditional retirement obligations (primarily for asbestos remediation).

The ARO liabilities for FES, OE and TE primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities (OE for its leasehold interest in Beaver Valley Unit 2 and Perry and TE for its leasehold interest in Beaver Valley Unit 2). The ARO liabilities for JCP&L, Met-Ed and Penelec primarily relate to the decommissioning of the TMI-2 nuclear generating facility. FES and the Utilities use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy, FES and the Utilities maintain nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2009 and 2008 were as follows:

	2009	2008
	(In millions)	
FE	$ 1,859	$ 1,700
FES	1,089	1,034
OE	121	117
TE	74	74
JCP&L	167	143
Met-Ed	266	226
Penelec	143	115

Accounting standards for conditional retirement obligations associated with tangible long-lived assets require recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not in the recognition of the liability.

The following table summarizes the changes to the ARO balances during 2009 and 2008.

ARO Reconciliation	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Balance as of January 1, 2008	$ 1,279	$ 810	$ 105	$ 2	$ 28	$ 90	$ 161	$ 82
Liabilities incurred	5	-	-	-	-	-	-	-
Liabilities settled	(3)	(2)	-	-	-	-	-	-
Accretion	84	55	5	-	2	5	10	5
Revisions in estimated cash flows	(18)[1]	-	(18)[1]	-	-	-	-	-
Balance as of December 31, 2008	1,347	863	92	2	30	95	171	87
Liabilities incurred	4	1	-	-	-	-	-	-
Accretion	90	58	6	-	2	7	11	6
Revisions in estimated cash flows	(16)	(1)	(12)	-	-	-	(2)	(1)
Balance as of December 31, 2009	$ 1,425	$ 921	$ 86	$ 2	$ 32	$ 102	$ 180	$ 92

(1) OE revised the estimated cash flows associated with the retired Gorge and Toronto plants based on an agreement to remediate asbestos at the sites within one year.

14. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had approximately $1.2 billion of short-term indebtedness as of December 31, 2009, comprised of $1.1 billion of borrowings under a $2.75 billion revolving line of credit, $100 million of other bank borrowings and $31 million of currently payable notes. Total short-term bank lines of committed credit to FirstEnergy and the Utilities as of January 31, 2010 were approximately $3.4 billion of which $1.7 billion was unused and available.

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

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of December 31, 2009:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FirstEnergy	$ 2,750	$ - (1)
FES	1,000	- (1)
OE	500	500
Penn	50	33 (2)
CEI	250 (3)	500
TE	250 (3)	500
JCP&L	425	411 (2)
Met-Ed	250	300 (2)
Penelec	250	300 (2)
ATSI	50 (4)	50

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

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

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

(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that ATSI has received regulatory approval to have short-term borrowings up to the same amount.

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

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2009 and 2008 were as follows:

	2009	2008
FE	0.74%	1.19%
FES	1.84%	1.08%
OE(1)	0.72%	-
CEI	1.13%	1.77%
TE	0.72%	1.46%
JCP&L(2)	-	1.46%
Met-Ed(2)	-	0.92%
Penelec	0.72%	0.95%

(1) In, 2008, OE's short-term borrowings consisted of noninterest-bearing notes related to its investment in certain low-income housing limited partnerships.

(2) JCP&L and Met-Ed had no outstanding short-term borrowings as of December 31, 2009.

The Utilities, with the exception of TE, JCP&L and Penn, each have a wholly owned subsidiary whose borrowings are secured by customer accounts receivable purchased from its respective parent company. The CEI subsidiary's borrowings are also secured by customer accounts receivable purchased from TE. Each subsidiary company has its own receivables financing arrangement and, as a separate legal entity with separate creditors, would have to satisfy its obligations to creditors before any of its remaining assets could be available to its parent company. In December 2009, the Met-Ed and Penelec Funding LLC receivables programs were renewed for a 364-day period. The Penn Power Funding LLC program was not renewed in 2009 and was thereafter terminated effective December 17, 2009. The receivables financing borrowing commitment by company are shown in the following table. There were no outstanding borrowings as of December 31, 2009.

Subsidiary Company	Parent Company	Commitment	Annual Facility Fee	Maturity
		(In millions)		
OES Capital, Incorporated	OE	$ 170	0.20 %	February 22, 2010
Centerior Funding Corporation	CEI	200	0.20	February 22, 2010
Met-Ed Funding LLC	Met-Ed	75	0.60	December 17, 2010
Penelec Funding LLC	Penelec	70	0.60	December 17, 2010
		$ 515		

15. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $12.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $12.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $118 million (but not more than $18 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy’s maximum potential assessment under these provisions would be $470 million (OE-$40 million, NGC-$408 million, and TE-$22 million) per incident but not more than $70 million (OE-$6 million, NGC-$61 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy’s subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $560 million (OE-$48 million, NGC-$486 million, TE-$26 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy’s present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $3 million (NGC-$3 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $60 million (OE-$6 million, NGC-$51 million, TE-$2 million, Met Ed, Penelec and JCP&L-$1 million in total) during a policy year.

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

(B) GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. As of December 31, 2009, outstanding guarantees and other assurances aggregated approximately $4.2 billion, consisting of parental guarantees - $1.0 billion, subsidiaries’ guarantees - $2.6 billion, surety bonds - $0.1 billion and LOCs - $0.5 billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.4 billion (included in the $1.0 billion discussed above) as of December 31, 2009 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or “material adverse event,” the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. On February 11, 2010, S&P issued a report lowering FirstEnergy’s and its subsidiaries’ credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral. Moody's and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010. As of December 31, 2009, FirstEnergy's maximum exposure under these collateral provisions was $648 million, consisting of $43 million due to “material adverse event” contractual clauses, $98 million due to an acceleration of payment or funding obligation, and $507 million due to a below investment grade credit rating including the $48 million related to the credit rating downgrade by S&P on February 11, 2010. Additionally, stress case conditions of a credit rating downgrade or “material adverse event” and hypothetical adverse price movements in the underlying commodity markets would increase this amount to $807 million, consisting of $51 million due to “material adverse event” contractual clauses, $98 million related to an acceleration of payment or funding obligation, and $658 million due to a below investment grade credit rating.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $101 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, 2009, and forward prices as of that date, FES had $179 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $129 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post higher amounts for margining.

In July 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has unconditionally and irrevocably guaranteed all of FGCO’s obligations under each of the leases (see Note 7). The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust’s undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES’ lease guaranty.

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

(C) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on FirstEnergy with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

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

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to $37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

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

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE’s and Penn’s settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_X and SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices or repowering and provides for stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree, including repowering Burger Units 4 and 5 for biomass fuel consumption, are currently estimated to be $399 million for 2010-2012.

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

In December 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU and Met-Ed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, which the Court granted on March 24, 2009. Specifically, Connecticut and New Jersey allege that "modifications" at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR or permitting under the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. The scope of Met-Ed’s indemnity obligation to and from Sithe Energy is disputed. Met-Ed filed a Motion to Dismiss the claims in New Jersey’s Amended Complaint and Connecticut’s Complaint in February and September of 2009, respectively. The Court granted Met-Ed's motion to dismiss New Jersey’s and Connecticut’s claims for injunctive relief against Met-Ed, but denied Met-Ed’s motion to dismiss the claims for civil penalties on statute of limitations grounds in order to allow the states to prove either that the application of the discovery rule or the doctrine of equitable tolling bars application of the statute of limitations.

In January 2009, the EPA issued a NOV to Reliant alleging NSR violations at the Portland Generation Station based on “modifications” dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA’s January 2009, NOV also alleged NSR violations at the Keystone and Shawville Stations based on “modifications” dating back to 1984. JCP&L, as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

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

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

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

National Ambient Air Quality Standards

In March 2005, the EPA finalized CAIR, covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia, based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR requires reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NO_X emissions to 1.3 million tons annually. CAIR was challenged in the U.S. Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." In September 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. In December 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. On July 10, 2009, the U.S. Court of Appeals for the District of Columbia ruled in a different case that a cap-and-trade program similar to CAIR, called the "NO_X SIP Call," cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the "8-hour" ozone NAAQS. FGCO's future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_X emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the U.S. Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition in May 2008. In October 2008, the EPA (and an industry group) petitioned the U.S. Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the EPA moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the EPA's petition and denied the industry group's petition. On October 21, 2009, the EPA opened a 30-day comment period on a proposed consent decree that would obligate the EPA to propose MACT regulations for mercury and other hazardous air pollutants by March 16, 2011, and to finalize the regulations by November 16, 2011. FGCO's future cost of compliance with MACT regulations may be substantial and will depend on the action taken by the EPA and on how any future regulations are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On December 23, 2009, the Supreme Court of Pennsylvania affirmed the Commonwealth Court of Pennsylvania ruling that Pennsylvania's mercury rule is "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing, by 2012, the amount of man-made GHG, including CO_2, emitted by developed countries. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, the December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement which recognized the scientific view that the increase in global temperature should be below two degrees Celsius, included a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020, and established the "Copenhagen Green Climate Fund" to support mitigation, adaptation, and other climate-related activities in developing countries. Once they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia, and the United States, would commit to quantified economy-wide emissions targets from 2020, while developing countries, including Brazil, China, and India, would agree to take mitigation actions, subject to their domestic measurement, reporting, and verification. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, on June 26, 2009. The Senate continues to consider a number of measures to regulate GHG emissions. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states, led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as "air pollutants" under the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate "air pollutants" from those and other facilities. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that the atmospheric concentrations of several key GHG threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key GHG and hence to the threat of climate change. Although the EPA's finding does not establish emission requirements for motor vehicles, such requirements are expected to occur through further rulemakings. Additionally, while the EPA's endangerment findings do not specifically address stationary sources, including electric generating plants EPA's expected establishment of emission requirements for motor vehicles would be expected to support the establishment of future emission requirements by the EPA for stationary sources. In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that will require FirstEnergy to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. Also in September 2009, EPA proposed new thresholds for GHG emissions that define when CAA permits under the NSR and Title V operating permits programs would be required. EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) for existing facilities under the Title V operating permits program and the Prevention of Significant Determination (PSD) portion of NSR. EPA is also proposing a significance level between 10,000 and 25,000 tpy CO2e to determine if existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit.

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

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

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA’s regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 1, 2009, the Supreme Court of the United States reversed one significant aspect of the Second Circuit Court’s opinion and decided that Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. FirstEnergy is studying various control options and their costs and effectiveness. Depending on the results of such studies and the EPA’s further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

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

Regulation of Waste Disposal

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. In February 2009, the EPA requested comments from the states on options for regulating coal combustion wastes, including regulation as non-hazardous waste or regulation as a hazardous waste. In March and June 2009, the EPA requested information from FGCO’s Bruce Mansfield Plant regarding the management of coal combustion wastes. In December 2009, EPA provided to FGCO the findings of its review of the Bruce Mansfield Plant’s coal combustion waste management practices. EPA observed that the waste management structures and the Plant “appeared to be well maintained and in good working order” and recommended only that FGCO “seal and maintain all asphalt surfaces.” On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. Additional regulations of fossil-fuel combustion waste products could have a significant impact on our management, beneficial use, and disposal, of coal ash. FGCO's future cost of compliance with any coal combustion waste regulations which may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the states.

The Utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of December 31, 2009, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $101 million (JCP&L - $74 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FirstEnergy - $24 million) have been accrued through December 31, 2009. Included in the total are accrued liabilities of approximately $67 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

(D) OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. 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. The class was decertified twice by the trial court, and appealed both times by the Plaintiffs, with the results being that: (1) the Appellate Division limited the class only to those customers directly impacted by the outages of JCP&L transformers in Red Bank, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation which resulted in planned and unplanned outages in the area during a 2-3 day period, and (2) in March 2007, the Appellate Division remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. On March 31, 2009, the trial court again granted JCP&L's motion to decertify the class. On April 20, 2009, the Plaintiffs filed a motion for leave to take an interlocutory appeal to the trial court's decision to decertify the class, which was granted by the Appellate Division on June 15, 2009. Plaintiffs filed their appellate brief on August 25, 2009, and JCP&L filed an opposition brief on September 25, 2009. On or about October 13, 2009, Plaintiffs filed their reply brief in further support of their appeal of the trial court's decision decertifying the class. The Appellate Division heard oral argument on January 5, 2010, before a three-judge panel. JCP&L is awaiting the Court's decision.

Nuclear Plant Matters

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. On November 5, 2009, the NRC issued a renewed operating license for Beaver Valley Power Station, Units 1 and 2. The operating licenses for these facilities were extended until 2036 and 2047 for Units 1 and 2, respectively.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2009, FirstEnergy had approximately $1.9 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy provided an additional $80 million parental guarantee associated with the funding of decommissioning costs for these units and indicated that it planned to contribute an additional $80 million to these trusts by 2010. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy's nuclear decommissioning trusts fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and its effects on particular businesses and the economy in general also affects the values of the nuclear decommissioning trusts. On June 18, 2009, the NRC informed FENOC that its review tentatively concluded that a shortfall existed in the decommissioning trust fund for Beaver Valley Unit 1. On November 24, 2009, FENOC submitted a revised decommissioning funding calculation using the NRC formula method based on the renewed license for Beaver Valley Unit 1, which extended operations until 2036. FENOC's submittal demonstrated that there was a de minimis shortfall. On December 11, 2009, the NRC's review of FirstEnergy's methodology for the funding of decommissioning of this facility concluded that there was reasonable assurance of adequate decommissioning funding at the time permanent termination of operations is expected. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

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.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. A final order identifying the individual damage amounts was issued on October 31, 2007 and the award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. On February 25, 2009, the federal district court denied JCP&L's motion to vacate the arbitration decision and granted the union's motion to confirm the award. JCP&L filed a Notice of Appeal to the Third Circuit and a Motion to Stay Enforcement of the Judgment on March 6, 2009. The appeal process could take as long as 24 months. The parties are participating in the federal court's mediation programs and have held private settlement discussions. JCP&L recognized a liability for the potential $16 million award in 2005. Post-judgment interest began to accrue as of February 25, 2009, and the liability will be adjusted accordingly.

FirstEnergy 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.

16. SEGMENT INFORMATION

Financial information for each of FirstEnergy's reportable segments is presented in the following table. FES and the Utilities do not have separate reportable operating segments. With the completion of transition to a fully competitive generation market in Ohio in 2009, the former Ohio Transitional Generation Services segment was combined with the Energy Delivery Services segment, consistent with how management views the business. Disclosures for FirstEnergy's operating segments for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

The energy delivery services segment transmits and distributes electricity through our eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its PLR and default service requirements in Ohio, Pennsylvania and New Jersey. Its revenues are primarily derived from the delivery of electricity within our service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Ohio, Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES and from non-affiliated power suppliers, the net PJM and MISO transmission expenses related to the delivery of the respective generation loads, and the deferral and amortization of certain fuel costs.

The competitive energy services segment supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the PLR and default service requirements of FirstEnergy's Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns or leases and operates 19 generating facilities with a net demonstrated capacity of 13,710 MWs and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from affiliated and non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment's customers.

The other segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment.

Segment Financial Information	**Energy Delivery Services**	**Competitive Energy Services**	**Other**	**Reconciling Adjustments**	**Consolidated**
			(In millions)		
2009					
External revenues	$ 11,144	$ 1,888	$ 37	$ (119)	$ 12,950
Internal revenues*	-	2,843	-	(2,826)	17
Total revenues	11,144	4,731	37	(2,945)	12,967
Depreciation and amortization	1,464	270	10	11	1,755
Investment income	139	121	-	(56)	204
Net interest charges	469	106	8	265	848
Income taxes	290	345	(265)	(125)	245
Net income	435	517	257	(219)	990
Total assets	22,978	10,584	607	135	34,304
Total goodwill	5,551	24	-	-	5,575
Property additions	750	1,262	149	42	2,203
2008					
External revenues	$ 12,068	$ 1,571	$ 72	$ (84)	$ 13,627
Internal revenues	-	2,968	-	(2,968)	-
Total revenues	12,068	4,539	72	(3,052)	13,627
Depreciation and amortization	1,154	243	4	13	1,414
Investment income	171	(34)	6	(84)	59
Net interest charges	408	108	2	184	702
Income taxes	611	314	(53)	(95)	777
Net income	916	472	116	(165)	1,339
Total assets	23,025	9,559	539	398	33,521
Total goodwill	5,551	24	-	-	5,575
Property additions	839	1,835	176	38	2,888
2007					
External revenues	$ 11,322	$ 1,468	$ 39	$ (27)	$ 12,802
Internal revenues	-	2,901	-	(2,901)	-
Total revenues	11,322	4,369	39	(2,928)	12,802
Depreciation and amortization	899	204	4	26	1,133
Investment income	241	16	1	(138)	120
Net interest charges	446	152	4	141	743
Income taxes	643	330	4	(94)	883
Net income	965	495	12	(160)	1,312
Total assets	23,826	7,669	303	513	32,311
Total goodwill	5,583	24	-	-	5,607
Property additions	814	740	21	58	1,633

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

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses and elimination of intersegment transactions.

Products and Services

Year	Electricity Sales
	(In millions)
2009	$ 12,032
2008	12,693
2007	11,944

17. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

In 2009, the FASB amended the derecognition guidance in the Transfers and Servicing Topic of the FASB Accounting Standards Codification and eliminated the concept of a QSPE. The amended guidance requires an evaluation of all existing QSPEs to determine whether they must be consolidated. This standard is effective for financial asset transfers that occur in fiscal years beginning after November 15, 2009. FirstEnergy does not expect this standard to have a material effect upon its financial statements.

In 2009, the FASB amended the consolidation guidance applied to VIEs. This standard replaces the quantitative approach previously required to determine which entity has a controlling financial interest in a VIE with a qualitative approach. Under the new approach, the primary beneficiary of a VIE is the entity that has both (a) the power to direct the activities of the VIE that most significantly impact the entity's economic performance, and (b) the obligation to absorb losses of the entity, or the right to receive benefits from the entity, that could be significant to the VIE. This standard also requires ongoing reassessments of whether an entity is the primary beneficiary of a VIE and enhanced disclosures about an entity's involvement in VIEs. The standard is effective for fiscal years beginning after November 15, 2009. FirstEnergy is currently evaluating the impact of adopting this standard on its financial statements.

In 2010, the FASB amended the Fair Value Measurements and Disclosures Topic of the FASB Accounting Standards Codification to require additional disclosures about 1) transfers of Level 1 and Level 2 fair value measurements, including the reason for transfers, 2) purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, 3) additional disaggregation to include fair value measurement disclosures for each class of assets and liabilities and 4) disclosure of inputs and valuation techniques used to measure fair value for both recurring and nonrecurring fair value measurements. The amendment is effective for fiscal years beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, which is effective for fiscal years beginning after December 15, 2010. FirstEnergy does not expect this standard to have a material effect upon its financial statements.

18. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' and the Utilities' operating revenues, operating expenses, investment income and interest expense include transactions with affiliated companies. These affiliated company transactions include PSAs between FES and the Utilities, support service billings from FESC and FENOC, interest on associated company notes and other transactions (see Note 7).

The Ohio Companies had a PSA with FES through December 31, 2009 to meet their PLR and default service obligations. Met-Ed and Penelec have a partial requirement PSA with FES to meet a portion of their PLR and default service obligations (see Note 9). FES is incurring interest expense through FGCO and NGC on associated company notes payable to the Ohio Companies and Penn related to the 2005 intra-system generation asset transfers. The primary affiliated company transactions for FES and the Utilities for the three years ended December 31, 2009 are as follows:

Affiliated Company Transactions - 2009	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Revenues:							
Electric sales to affiliates	$ 2,826	$ 187	$ -	$ 35	$ -	$ -	$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Other*	17	-	-	-	-	-	-
Expenses:							
Purchased power from affiliates	222	991	735	393	-	365	342
Support services	563	140	60	55	85	52	53
Investment Income:							
Interest income from affiliates	-	15	-	17	-	-	-
Interest income from FirstEnergy	4	1	-	-	-	-	-
Interest Expense:							
Interest expense to affiliates	6	5	17	-	4	3	2
Interest expense to FirstEnergy	4	-	1	1	-	-	1

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

Affiliated Company Transactions - 2008	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Revenues:							
Electric sales to affiliates	$ 2,968	$ 70	$ -	$ 30	$ -	$ -	$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Expenses:							
Purchased power from affiliates	101	1,203	766	411	-	304	284
Support services	552	145	67	62	90	57	56
Investment Income:							
Interest income from affiliates	-	15	1	20	1	-	1
Interest income from FirstEnergy	13	13	-	-	-	-	-
Interest Expense:							
Interest expense to affiliates	4	3	19	1	3	2	2
Interest expense to FirstEnergy	26	-	7	2	5	4	5

Affiliated Company Transactions - 2007	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Revenues:							
Electric sales to affiliates	$ 2,901	$ 73	$ 92	$ 167	$ -	$ -	$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Expenses:							
Purchased power from affiliates	234	1,261	770	392	-	290	285
Support services	560	146	70	55	100	54	58
Investment Income:							
Interest income from affiliates	-	30	17	18	1	1	1
Interest income from FirstEnergy	28	29	2	-	-	-	-
Interest Expense:							
Interest expense to affiliates	31	1	1	-	1	1	1
Interest expense to FirstEnergy	34	-	1	10	11	10	11

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days.

19. SUPPLEMENTAL GUARANTOR INFORMATION

As discussed, in Note 7, FES has fully and unconditionally guaranteed all of FGCO's obligations under each of the leases associated with Bruce Mansfield Unit 1. The consolidating statements of income for the three years ended December 31, 2009, consolidating balance sheets as of December 31, 2009, and December 31, 2008, and condensed consolidating statements of cash flows for the three years ended December 31, 2009, for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved (see Note 7). The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 4,390,111	$ 2,216,237	$ 1,360,522	$ (3,238,533)	$ 4,728,337
EXPENSES:					
Fuel	18,416	971,021	138,026	-	1,127,463
Purchased power from affiliates	3,220,197	18,336	222,406	(3,238,533)	222,406
Purchased power from non-affiliates	996,383	-	-	-	996,383
Other operating expenses	220,660	395,330	518,473	48,762	1,183,225
Provision for depreciation	4,147	121,007	139,488	(5,249)	259,393
General taxes	18,214	44,075	24,626	-	86,915
Total expenses	4,478,017	1,549,769	1,043,019	(3,195,020)	3,875,785
OPERATING INCOME	(87,906)	666,468	317,503	(43,513)	852,552
OTHER INCOME (EXPENSE):					
Investment income	5,297	683	119,246	-	125,226
Miscellaneous income (expense), including net income from equity investees	656,451	(3,931)	61	(645,911)	6,670
Interest expense to affiliates	(135)	(5,619)	(4,352)	-	(10,106)
Interest expense - other	(44,837)	(99,802)	(62,034)	64,553	(142,120)
Capitalized interest	212	49,577	10,363	-	60,152
Total other income (expense)	616,988	(59,092)	63,284	(581,358)	39,822
INCOME BEFORE INCOME TAXES	529,082	607,376	380,787	(624,871)	892,374
INCOME TAXES	(48,002)	207,171	135,785	20,336	315,290
NET INCOME	$ 577,084	$ 400,205	$ 245,002	$ (645,207)	$ 577,084

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2008	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 4,470,112	$ 2,275,451	$ 1,204,534	$ (3,431,744)	$ 4,518,353
EXPENSES:					
Fuel	16,322	1,171,993	126,978	-	1,315,293
Purchased power from non-affiliates	778,882	-	-	-	778,882
Purchased power from affiliates	3,417,126	14,618	101,409	(3,431,744)	101,409
Other operating expenses	116,972	416,723	502,096	48,757	1,084,548
Provision for depreciation	5,986	119,763	111,529	(5,379)	231,899
General taxes	19,260	46,153	22,591	-	88,004
Total expenses	4,354,548	1,769,250	864,603	(3,388,366)	3,600,035
OPERATING INCOME	115,564	506,201	339,931	(43,378)	918,318
OTHER INCOME (EXPENSE):					
Investment income (loss)	10,953	2,034	(35,665)	-	(22,678)
Miscellaneous income (expense), including net income from equity investees	438,214	(5,400)	-	(431,116)	1,698
Interest expense to affiliates	(314)	(20,342)	(9,173)	-	(29,829)
Interest expense - other	(24,674)	(95,926)	(56,486)	65,404	(111,682)
Capitalized interest	142	39,934	3,688	-	43,764
Total other income (expense)	424,321	(79,700)	(97,636)	(365,712)	(118,727)
INCOME BEFORE INCOME TAXES	539,885	426,501	242,295	(409,090)	799,591
INCOME TAXES	33,475	155,100	90,247	14,359	293,181
NET INCOME	$ 506,410	$ 271,401	$ 152,048	$ (423,449)	$ 506,410

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2007	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 4,345,790	$ 1,982,166	$ 1,062,026	$ (3,064,955)	$ 4,325,027
EXPENSES:					
Fuel	26,169	942,946	117,895	-	1,087,010
Purchased power from non-affiliates	764,090	-	-	-	764,090
Purchased power from affiliates	3,038,786	186,415	73,844	(3,064,955)	234,090
Other operating expenses	161,797	352,856	514,389	11,997	1,041,039
Provision for depreciation	2,269	99,741	92,239	(1,337)	192,912
General taxes	20,953	41,456	24,689	-	87,098
Total expenses	4,014,064	1,623,414	823,056	(3,054,295)	3,406,239
OPERATING INCOME	331,726	358,752	238,970	(10,660)	918,788
OTHER INCOME (EXPENSE):					
Investment income	22,845	2,799	15,793	-	41,437
Miscellaneous income (expense), including net income from equity investees	319,133	1,411	(913)	(308,192)	11,439
Interest expense to affiliates	(1,320)	(48,536)	(15,645)	-	(65,501)
Interest expense - other	(9,503)	(59,412)	(39,458)	16,174	(92,199)
Capitalized interest	35	14,369	5,104	-	19,508
Total other income (expense)	331,190	(89,369)	(35,119)	(292,018)	(85,316)
INCOME BEFORE INCOME TAXES	662,916	269,383	203,851	(302,678)	833,472
INCOME TAXES	134,052	90,801	77,467	2,288	304,608
NET INCOME	$ 528,864	$ 178,582	$ 126,384	$ (304,966)	$ 528,864

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ -	$ 3	$ 9	$ -	$ 12
Receivables-					
Customers	195,107	-	-	-	195,107
Associated companies	305,298	175,730	134,841	(297,308)	318,561
Other	28,394	10,960	12,518	-	51,872
Notes receivable from associated companies	416,404	240,836	147,863	-	805,103
Materials and supplies, at average cost	17,265	307,079	215,197	-	539,541
Prepayments and other	80,025	18,356	9,401	-	107,782
	1,042,493	752,964	519,829	(297,308)	2,017,978
PROPERTY, PLANT AND EQUIPMENT:					
In service	90,474	5,478,346	5,174,835	(386,023)	10,357,632
Less - Accumulated provision for depreciation	13,649	2,778,320	1,910,701	(171,512)	4,531,158
	76,825	2,700,026	3,264,134	(214,511)	5,826,474
Construction work in progress	6,032	2,049,078	368,336	-	2,423,446
	82,857	4,749,104	3,632,470	(214,511)	8,249,920
INVESTMENTS:					
Nuclear plant decommissioning trusts	-	-	1,088,641	-	1,088,641
Investment in associated companies	4,477,602	-	-	(4,477,602)	-
Other	1,137	21,127	202	-	22,466
	4,478,739	21,127	1,088,843	(4,477,602)	1,111,107
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	93,379	381,849	-	(388,602)	86,626
Goodwill	24,248	-	-	-	24,248
Property taxes	-	27,811	22,314	-	50,125
Unamortized sale and leaseback costs	-	16,454	-	56,099	72,553
Other	99,411	71,179	18,755	(51,114)	138,231
	217,038	497,293	41,069	(383,617)	371,783
	$ 5,821,127	$ 6,020,488	$ 5,282,211	$ (5,373,038)	$ 11,750,788
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 736	$ 646,402	$ 922,429	$ (18,640)	$ 1,550,927
Short-term borrowings-					
Associated companies	-	9,237	-	-	9,237
Other	100,000	-	-	-	100,000
Accounts payable-					
Associated companies	261,788	170,446	295,045	(261,201)	466,078
Other	51,722	193,641	-	-	245,363
Accrued taxes	44,213	61,055	22,777	(44,887)	83,158
Other	173,015	132,314	16,734	36,994	359,057
	631,474	1,213,095	1,256,985	(287,734)	2,813,820
CAPITALIZATION:					
Common stockholder's equity	3,514,571	2,346,515	2,119,488	(4,466,003)	3,514,571
Long-term debt and other long-term obligations	1,519,339	1,906,818	554,825	(1,269,330)	2,711,652
	5,033,910	4,253,333	2,674,313	(5,735,333)	6,226,223
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	-	-	-	992,869	992,869
Accumulated deferred income taxes	-	-	342,840	(342,840)	-
Accumulated deferred investment tax credits	-	36,359	22,037	-	58,396
Asset retirement obligations	-	25,714	895,734	-	921,448
Retirement benefits	33,144	170,891	-	-	204,035
Property taxes	-	27,811	22,314	-	50,125
Lease market valuation liability	-	262,200	-	-	262,200
Other	122,599	31,085	67,988	-	221,672
	155,743	554,060	1,350,913	650,029	2,710,745
	$ 5,821,127	$ 6,020,488	$ 5,282,211	$ (5,373,038)	$ 11,750,788

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2008	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ -	$ 39	$ -	$ -	$ 39
Receivables-					
Customers	86,123	-	-	-	86,123
Associated companies	363,226	225,622	113,067	(323,815)	378,100
Other	991	11,379	12,256	-	24,626
Notes receivable from associated companies	107,229	21,946	-	-	129,175
Materials and supplies, at average cost	5,750	303,474	212,537	-	521,761
Prepayments and other	76,773	35,102	660	-	112,535
	640,092	597,562	338,520	(323,815)	1,252,359
PROPERTY, PLANT AND EQUIPMENT:					
In service	134,905	5,420,789	4,705,735	(389,525)	9,871,904
Less - Accumulated provision for depreciation	13,090	2,702,110	1,709,286	(169,765)	4,254,721
	121,815	2,718,679	2,996,449	(219,760)	5,617,183
Construction work in progress	4,470	1,441,403	301,562	-	1,747,435
	126,285	4,160,082	3,298,011	(219,760)	7,364,618
INVESTMENTS:					
Nuclear plant decommissioning trusts	-	-	1,033,717	-	1,033,717
Long-term notes receivable from associated companies	-	-	62,900	-	62,900
Investment in associated companies	3,596,152	-	-	(3,596,152)	-
Other	1,913	59,476	202	-	61,591
	3,598,065	59,476	1,096,819	(3,596,152)	1,158,208
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	24,703	476,611	-	(233,552)	267,762
Lease assignment receivable from associated companies	-	71,356	-	-	71,356
Goodwill	24,248	-	-	-	24,248
Property taxes	-	27,494	22,610	-	50,104
Unamortized sale and leaseback costs	-	20,286	-	49,646	69,932
Other	59,642	59,674	21,743	(44,625)	96,434
	108,593	655,421	44,353	(228,531)	579,836
	$ 4,473,035	$ 5,472,541	$ 4,777,703	$ (4,368,258)	$ 10,355,021
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 5,377	$ 925,234	$ 1,111,183	$ (16,896)	$ 2,024,898
Short-term borrowings-					
Associated companies	1,119	257,357	6,347	-	264,823
Other	1,000,000	-	-	-	1,000,000
Accounts payable-					
Associated companies	314,887	221,266	250,318	(314,133)	472,338
Other	35,367	119,226	-	-	154,593
Accrued taxes	8,272	60,385	30,790	(19,681)	79,766
Other	61,034	136,867	13,685	36,853	248,439
	1,426,056	1,720,335	1,412,323	(313,857)	4,244,857
CAPITALIZATION:					
Common stockholder's equity	2,944,423	1,832,678	1,752,580	(3,585,258)	2,944,423
Long-term debt and other long-term obligations	61,508	1,328,921	469,839	(1,288,820)	571,448
	3,005,931	3,161,599	2,222,419	(4,874,078)	3,515,871
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	-	-	-	1,026,584	1,026,584
Accumulated deferred income taxes	-	-	206,907	(206,907)	-
Accumulated deferred investment tax credits	-	39,439	23,289	-	62,728
Asset retirement obligations	-	24,134	838,951	-	863,085
Retirement benefits	22,558	171,619	-	-	194,177
Property taxes	-	27,494	22,610	-	50,104
Lease market valuation liability	-	307,705	-	-	307,705
Other	18,490	20,216	51,204	-	89,910
	41,048	590,607	1,142,961	819,677	2,594,293
	$ 4,473,035	$ 5,472,541	$ 4,777,703	$ (4,368,258)	$ 10,355,021

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (20,027)	$ 790,411	$ 621,649	$ (17,744)	$ 1,374,289
CASH FLOWS FROM FINANCING ACTIVITIES:					
New financing-					
Long-term debt	1,498,087	576,800	363,515	-	2,438,402
Equity contributions from parent	-	100,000	150,000	(250,000)	-
Redemptions and repayments-					
Long-term debt	(1,766)	(320,754)	(404,383)	17,747	(709,156)
Short-term borrowings, net	(901,119)	(248,120)	(6,347)	-	(1,155,586)
Other	(12,054)	(6,157)	(3,576)	(3)	(21,790)
Net cash provided from financing activities	583,148	101,769	99,209	(232,256)	551,870
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(4,372)	(671,691)	(546,869)	-	(1,222,932)
Proceeds from asset sales	-	18,371	-	-	18,371
Sales of investment securities held in trusts	-	-	1,379,154	-	1,379,154
Purchases of investment securities held in trusts	-	-	(1,405,996)	-	(1,405,996)
Loans to associated companies, net	(309,175)	(218,890)	(147,863)	-	(675,928)
Investment in subsidiaries	(250,000)	-	-	250,000	-
Other	426	(20,006)	725	-	(18,855)
Net cash used for investing activities	(563,121)	(892,216)	(720,849)	250,000	(1,926,186)
Net change in cash and cash equivalents	-	(36)	9	-	(27)
Cash and cash equivalents at beginning of year	-	39	-	-	39
Cash and cash equivalents at end of year	$ -	$ 3	$ 9	$ -	$ 12

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2008	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM OPERATING ACTIVITIES	$ 40,791	$ 350,986	$ 478,047	$ (16,896)	$ 852,928
CASH FLOWS FROM FINANCING ACTIVITIES:					
New financing-					
Long-term debt	-	353,325	265,050	-	618,375
Equity contributions from parent	280,000	675,000	175,000	(850,000)	280,000
Short-term borrowings, net	701,119	18,571	-	(18,931)	700,759
Redemptions and repayments-					
Long-term debt	(2,955)	(293,349)	(183,132)	16,896	(462,540)
Short-term borrowings, net	-	-	(18,931)	18,931	-
Common stock dividend payment	(43,000)	-	-	-	(43,000)
Other	-	(3,107)	(2,040)	-	(5,147)
Net cash provided from financing activities	935,164	750,440	235,947	(833,104)	1,088,447
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(43,244)	(1,047,917)	(744,468)	-	(1,835,629)
Proceeds from asset sales	-	23,077	-	-	23,077
Sales of investment securities held in trusts	-	-	950,688	-	950,688
Purchases of investment securities held in trusts	-	-	(987,304)	-	(987,304)
Loans repayments from (loans to) associated companies	(83,457)	(21,946)	69,012	-	(36,391)
Investment in subsidiary	(850,000)	-	-	850,000	-
Other	744	(54,601)	(1,922)	-	(55,779)
Net cash used for investing activities	(975,957)	(1,101,387)	(713,994)	850,000	(1,941,338)
Net change in cash and cash equivalents	(2)	39	-	-	37
Cash and cash equivalents at beginning of year	2	-	-	-	2
Cash and cash equivalents at end of year	$ -	$ 39	$ -	$ -	$ 39

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2007	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (18,017)	$ 55,172	$ 263,468	$ (6,306)	$ 294,317
CASH FLOWS FROM FINANCING ACTIVITIES:					
New financing-					
Long-term debt	-	1,576,629	179,500	(1,328,919)	427,210
Equity contributions from parent	700,000	700,000	-	(700,000)	700,000
Short-term borrowings, net	300,000	-	25,278	(325,278)	-
Redemptions and repayments-					
Common stock	(600,000)	-	-	-	(600,000)
Long-term debt	-	(1,048,647)	(494,070)	6,306	(1,536,411)
Short-term borrowings, net	-	(783,599)	-	325,278	(458,321)
Common stock dividend payment	(117,000)	-	-	-	(117,000)
Other	-	(3,474)	(1,725)	-	(5,199)
Net cash provided from (used for) financing activities	283,000	440,909	(291,017)	(2,022,613)	(1,589,721)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(10,603)	(502,311)	(225,795)	-	(738,709)
Proceeds from asset sales	-	12,990	-	-	12,990
Proceeds from sale and leaseback transaction	-	-	-	1,328,919	1,328,919
Sales of investment securities held in trusts	-	-	655,541	-	655,541
Purchases of investment securities held in trusts	-	-	(697,763)	-	(697,763)
Loans repayments from associated companies	441,966	-	292,896	-	734,862
Investment in subsidiary	(700,000)	-	-	700,000	-
Other	3,654	(6,760)	2,670	-	(436)
Net cash provided from (used for) investing activities	(264,983)	(496,081)	27,549	2,028,919	1,295,404
Net change in cash and cash equivalents	-	-	-	-	-
Cash and cash equivalents at beginning of year	2	-	-	-	2
Cash and cash equivalents at end of year	$ 2	$ -	$ -	$ -	$ 2

20. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2009 and 2008.

Three Months Ended	Revenues	Operating Income (Loss)	Income (Loss) Before Income Taxes	Income Taxes (Benefit)	Earnings Available To FirstEnergy
			(In millions)		
FE					
March 31, 2009	$ 3,334.0	$ 346.0	$ 169.0	$ 54.0	$ 119.0
March 31, 2008	3,277.0	618.0	464.0	187.0	276.0
June 30, 2009	3,271.0	802.0	656.0	248.0	414.0
June 30, 2008	3,245.0	582.0	423.0	160.0	263.0
September 30,2009	3,408.0	487.0	358.0	128.0	234.0
September 30,2008	3,904.0	846.0	709.0	238.0	471.0
December 31, 2009	2,954.0	244.0	52.0	(185.0)	239.0
December 31, 2008	3,201.0	713.0	520.0	192.0	332.0
FES					
March 31, 2009	$ 1,226.1	$ 304.3	$ 262.5	$ 91.8	$ 170.7
March 31, 2008	1,099.1	175.7	147.8	57.8	90.0
June 30, 2009	1,341.2	468.9	466.6	169.2	297.4
June 30, 2008	1,071.3	142.2	115.4	47.3	68.1
September 30,2009	1,104.6	175.7	310.8	111.2	199.7
September 30,2008	1,241.6	288.8	278.9	93.2	185.7
December 31, 2009	1,056.4	(96.3)	(147.5)	(56.9)	(90.7)
December 31, 2008	1,106.4	311.6	257.5	94.9	162.6
OE					
March 31, 2009	$ 749.0	$ 30.2	$ 15.7	$ 4.0	$ 11.5
March 31, 2008	652.6	77.1	70.9	26.9	43.9
June 30, 2009	672.2	58.8	50.5	16.9	33.5
June 30, 2008	609.6	76.1	70.7	21.7	48.8
September 30,2009	602.5	52.8	50.6	15.9	34.6
September 30,2008	702.3	100.0	101.1	28.5	72.5
December 31, 2009 *	493.2	87.1	71.8	29.4	42.3
December 31, 2008	637.3	80.8	68.2	21.5	46.5
CEI					
March 31, 2009	$ 449.7	$ (144.1)	$ (166.9)	$ (61.5)	$ (105.9)
March 31, 2008	437.3	110.8	88.8	30.3	57.9
June 30, 2009	475.1	98.5	74.2	26.5	47.3
June 30, 2008	434.4	123.4	100.8	33.8	66.6
September 30,2009	435.5	61.6	35.1	9.8	25.0
September 30,2008	524.1	159.9	136.8	43.0	93.4
December 31, 2009	315.8	64.7	36.4	15.0	20.9
December 31, 2008	420.1	120.5	96.9	29.7	66.6

* Includes a $4.8 million adjustment that increased net income in the fourth quarter of 2009 related to prior periods. (See Note 10 for description of adjustment).

Three Months Ended	Revenues	Operating Income (Loss)	Income (Loss) Before Income Taxes	Income Taxes (Benefit)	Earnings Available To FirstEnergy
			(In millions)		
TE					
March 31, 2009	$ 244.8	$ 2.2	$ 0.9	$ (0.1)	$ 1.0
March 31, 2008	211.7	26.1	25.1	8.1	17.0
June 30, 2009	226.2	10.1	9.8	3.4	6.4
June 30, 2008	221.5	30.9	28.7	7.4	21.3
September 30,2009	213.5	10.2	7.0	(0.1)	7.1
September 30,2008	251.1	45.1	43.4	12.2	31.2
December 31, 2009 **	149.4	23.8	14.2	4.7	9.5
December 31, 2008	211.2	10.8	7.6	2.1	5.4
Met-Ed					
March 31, 2009	$ 429.7	$ 37.7	$ 28.4	$ 11.7	$ 16.6
March 31, 2008	400.3	45.6	38.9	16.7	22.2
June 30, 2009	377.6	27.8	17.0	7.0	10.0
June 30, 2008	392.0	37.8	32.7	12.9	19.8
September 30,2009	445.5	24.2	13.1	2.3	10.7
September 30,2008	455.5	45.1	38.3	16.3	22.0
December 31, 2009	436.2	37.2	25.6	7.6	18.2
December 31, 2008	405.2	46.1	39.0	15.0	24.0
Penelec					
March 31, 2009	$ 388.6	$ 44.2	$ 31.8	$ 13.1	$ 18.7
March 31, 2008	395.5	56.0	39.7	18.3	21.4
June 30, 2009	331.7	36.0	25.1	10.2	14.8
June 30, 2008	351.4	44.2	30.4	12.0	18.4
September 30,2009	355.5	32.3	21.8	6.0	15.8
September 30,2008	389.8	46.6	31.7	9.1	22.6
December 31, 2009	373.1	49.4	32.4	16.4	16.1
December 31, 2008	376.9	57.7	44.0	18.2	25.8
JCP&L					
March 31, 2009	$ 773.7	$ 77.1	$ 50.1	$ 22.6	$ 27.6
March 31, 2008	794.2	86.9	62.4	28.4	34.0
June 30, 2009	708.1	95.4	67.9	29.8	38.1
June 30, 2008	834.7	97.4	74.4	31.5	42.9
September 30,2009	868.2	133.7	105.6	43.4	62.2
September 30,2008	1,102.6	157.7	131.7	55.8	75.9
December 31, 2009	642.7	84.1	55.7	13.0	42.6
December 31, 2008	740.8	92.5	66.7	32.5	34.2

** Includes a $2.5 million adjustment that increased net income in the fourth quarter of 2009 related to prior periods. (See Note 10 for description of adjustment).

21. SUBSEQUENT EVENTS

On February 11, 2010, FirstEnergy and Allegheny Energy, Inc. (Allegheny) announced that both companies' boards of directors unanimously approved a definitive agreement in which the companies would combine in a stock-for-stock transaction.

Under the terms of the agreement, Allegheny shareholders would receive 0.667 of a share of FirstEnergy common stock in exchange for each share of Allegheny they own. Based on the closing stock prices for both companies on February 10, 2010, Allegheny shareholders would receive a value of $27.65 per share, or $4.7 billion in the aggregate. FirstEnergy would also assume approximately $3.8 billion of Allegheny net debt.

The merger is conditioned upon, among other things, the approval of the shareholders of both companies, as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approval by the FERC, the Maryland Public Service Commission, the PPUC, the Virginia State Corporation Commission and the West Virginia Public Service Commission. The merger is also conditioned on effectiveness at the SEC of FirstEnergy's registration statement with respect to the shares to be issued in the transaction. The companies anticipate that the necessary approvals may be obtained within 12-14 months.

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

FIRSTENERGY CORP.

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS
(Unaudited)

For the Years Ended December 31,	2009	2008	2007	2006	2005	2004	1999
GENERAL FINANCIAL INFORMATION							
(Dollars in millions)							
Revenues	$ 12,967	$ 13,627	$ 12,802	$ 11,501	$ 11,358	$ 11,600	$6,320
Earnings Available to FirstEnergy Corp.	$ 1,006	$ 1,342	$ 1,309	$ 1,254	$ 861	$ 878	$568
SEC Ratio of Earnings to							
Fixed Charges	2.08	3.27	3.21	3.14	2.74	2.64	2.01
Capital Expenditures	$ 1,770	$ 2,150	$ 1,496	$ 1,170	$ 1,144	$ 731	$ 474
Total Capitalization	$ 20,465	$ 17,415	$ 17,876	$ 17,604	$ 17,564	$ 18,977	$ 11,470
Capitalization Ratios:							
Total Equity	41.8 %	47.7 %	50.4 %	51.5 %	52.5 %	45.5 %	39.8
Preferred and Preference Stock:							
Not Subject to Mandatory Redemption	-	-	-	-	1.0	1.8	5.7
Subject to Mandatory Redemption	-	-	-	-	-	-	2.2
Long-Term Debt	58.2	52.3	49.6	48.5	46.5	52.7	52.3
Total Capitalization	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0
Average Capital Costs:							
Preferred and Preference Stock		-	-	-	5.67%	6.51%	7.99%
Long-Term Debt	5.91%	5.95%	5.89%	6.33%	6.05%	5.93%	7.65%
COMMON STOCK DATA							
Earnings per Share (a):							
Basic	$ 3.31	$ 4.41	$ 4.27	$ 3.85	$ 2.68	$ 2.77	$ 2.50
Diluted	$ 3.29	$ 4.38	$ 4.22	$ 3.82	$ 2.67	$ 2.76	$ 2.50
Return on Average Common Equity (a)	11.7%	14.7%	14.9%	13.5%	10.0%	10.8%	12.7%
Dividends Paid per Share	$ 2.20	$ 2.20	$ 2.00	$ 1.80	$ 1.67	$ 1.50	$ 1.50
Dividend Payout Ratio (a)	66%	50%	47%	47%	62%	54%	60%
Dividend Yield	4.7%	4.5%	2.8%	3.0%	3.4%	3.8%	6.6%
Price/Earnings Ratio (a)	14.0	11.0	17.0	15.7	18.3	14.3	9.1
Book Value per Share	$ 28.08	$ 27.17	$ 29.45	$ 28.35	$ 27.98	$ 26.20	$ 20.22
Market Price per Share	$ 46.45	$ 48.58	$ 72.34	$ 60.30	$ 48.99	$ 39.51	$ 22.69
Ratio of Market Price to Book Value	165%	179%	246%	213%	175%	151%	112%
OPERATING STATISTICS (b)							
Generation Kilowatt-Hour Sales (Millions):							
Residential	36,524	38,845	39,158	37,618	34,716	31,781	32,616
Commercial	32,056	34,405	36,879	35,390	32,878	32,114	30,311
Industrial	28,234	32,345	33,476	34,309	32,907	31,675	30,422
Other	519	538	540	542	547	504	566
Total Retail	97,333	106,133	110,053	107,859	101,048	96,074	93,915
Total Wholesale	21,126	24,654	24,114	23,083	28,521	53,268	14,631
Total Sales	118,459	130,787	134,167	130,942	129,569	149,342	108,546
Customers Served:							
Residential	3,964,341	3,963,229	3,956,837	3,959,043	3,941,030	3,916,855	3,767,534
Commercial	517,574	518,982	517,251	514,056	509,933	500,695	455,919
Industrial	10,128	10,225	10,367	10,458	10,637	10,597	19,549
Other	6,283	6,196	6,054	6,356	6,124	5,654	5,992
Total	4,498,326	4,498,632	4,490,509	4,489,913	4,467,724	4,433,801	4,248,994
Number of Employees	13,379	14,698	14,534	13,739	14,586	15,245	19,470

(a) Before discontinued operations in 2006, 2005 and 2004, and accounting changes in 2005.
(b) Reflects pro forma combined FirstEnergy and GPU statistics in 1999

Shareholder Services

Transfer Agent and Registrar

American Stock Transfer & Trust Company, LLC (AST) acts as the Transfer Agent, Dividend Paying Agent, and Shareholder Records Agent. Shareholders wanting to transfer stock, or needing assistance or information, can send their stock or write to FirstEnergy Corp., c/o American Stock Transfer & Trust Company, LLC, P. O. Box 2016, New York, NY 10272-2016. Shareholders also can call 1-800-736-3402, between 8:00 a.m. and 7:00 p.m., Monday through Thursday; or between 8:00 a.m. and 5:00 p.m. on Friday, Eastern time. For Internet access to general shareholder and account information, visit the AST Web site at *www.amstock.com* and click the FirstEnergy logo.

Stock Listing and Trading

Newspapers generally report FirstEnergy common stock under the abbreviation FSTENGY, but this can vary depending upon the newspaper. The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

Direct Dividend Deposit

Shareholders can have their dividend payments automatically deposited to checking or savings accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact AST at 1-800-736-3402 to receive an authorization form.

Stock Investment Plan

Shareholders and others can purchase or sell shares of FirstEnergy common stock through the Company's Stock Investment Plan. Investors who are not registered shareholders can enroll with an initial $250 investment. Participants can invest all or some of their dividends or make optional payments at any time of at least $25 per payment, up to $100,000 annually. Contact AST at 1-800-736-3402 to receive an enrollment form.

Safekeeping of Shares

Shareholders can request that AST hold their shares of FirstEnergy common stock in safekeeping. To take advantage of this service, shareholders should forward their common stock certificates to AST along with a signed letter requesting that AST hold the shares. Shareholders also should state whether future dividends for the held shares are to be reinvested or paid in cash. The certificates should not be endorsed, and registered mail is suggested. The shares will be held in uncertificated form, and AST will make certificates available to shareholders upon request. Shares held in safekeeping will be reported on dividend check stubs or Stock Investment Plan statements.

Form 10-K Annual Report

Form 10-K, the Annual Report to the Securities and Exchange Commission, will be sent to you without charge upon written request to Rhonda S. Ferguson, Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You can also view the Form 10-K by visiting FirstEnergy's Web site at *www.firstenergycorp.com/ir.*

Institutional Investor and Security Analyst Inquiries

Institutional investors and security analysts should direct inquiries to: Ronald E. Seeholzer, Vice President, Investor Relations, 330-384-5415.

Annual Meeting of Shareholders

Shareholders are invited to attend the 2010 Annual Meeting of Shareholders on Tuesday, May 18, at 10:30 a.m. Eastern time, at the John S. Knight Center, 77 East Mill Street, Akron, Ohio. Registered shareholders not attending the meeting can appoint a proxy and vote on the items of business by telephone, Internet, or by completing and returning the proxy card that is sent to them. Shareholders whose shares are held in the name of a broker can attend the meeting if they present a letter from their broker indicating ownership of FirstEnergy common stock on the record date of March 22, 2010.

FirstEnergy has included as Exhibit 31 to its Annual Report on Form 10-K for fiscal year 2009 filed with the Securities and Exchange Commission certificates of FirstEnergy's Chief Executive Officer and Chief Financial Officer certifying the quality of the Company's public disclosure.

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FirstEnergy®

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