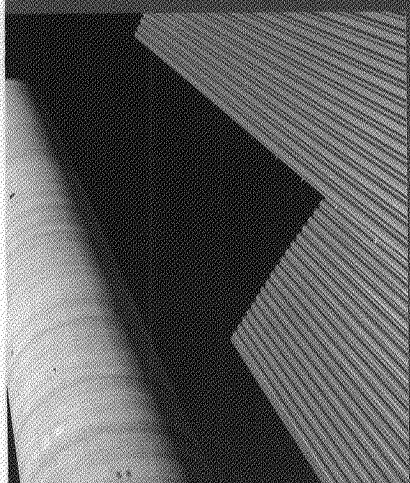
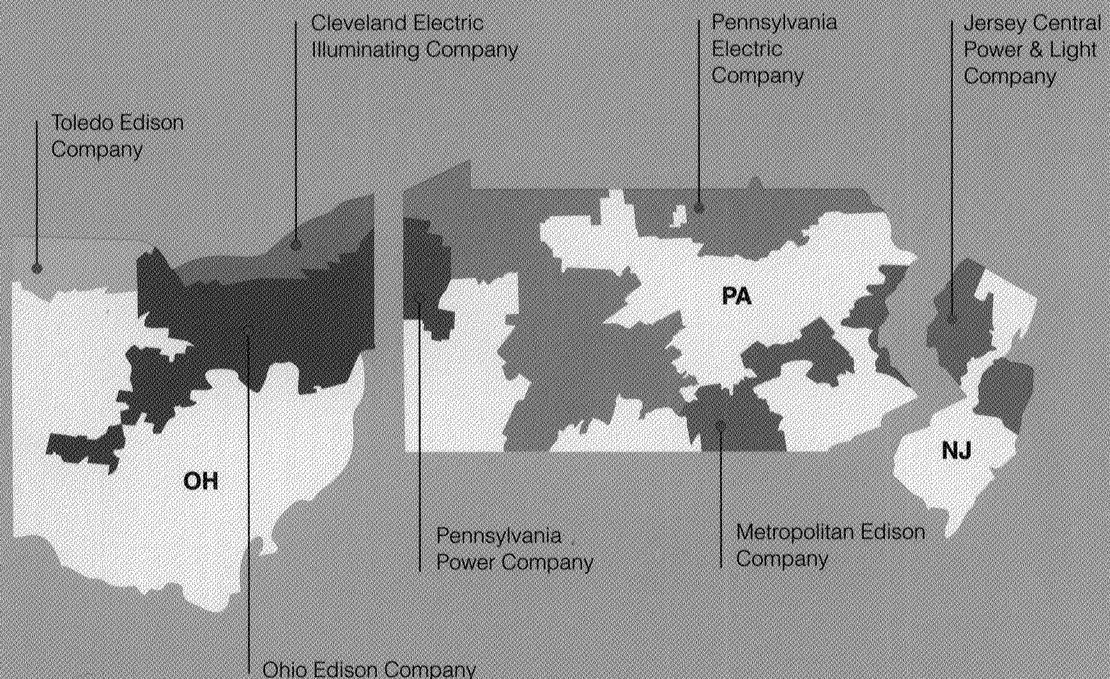
FirstEnergy



2008 Annual Report

FirstEnergy Electric Utility Operating Companies



Corporate Profile

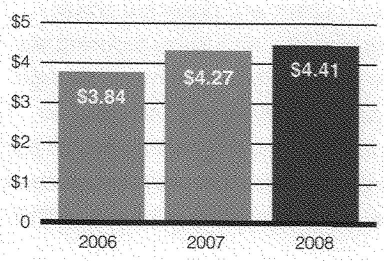
FirstEnergy is a diversified energy company headquartered in Akron, Ohio. Its subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services. Its seven electric utility operating companies comprise the nation's fifth-largest investor-owned electric system, based on 4.5 million customers served within a 36,100-square-mile area of Ohio, Pennsylvania and New Jersey. Its generation subsidiaries control more than 14,000 megawatts of capacity.

On the cover: Construction nears completion on the 850-foot-tall chimney and an equipment building that are part of the $1.7 billion air quality compliance project at our W. H. Sammis Plant in Stratton, Ohio.

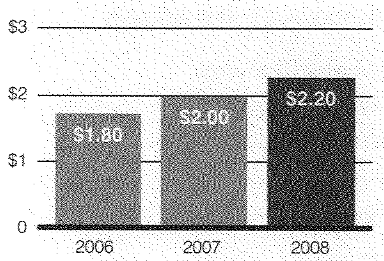
Financial Highlights

(Dollars in millions, except per share amounts)	**2008**	2007
Total revenues	**$13,627**	$12,802
Net income	**$ 1,342**	$ 1,309
Basic earnings per common share	**$ 4.41**	$ 4.27
Diluted earnings per common share	**$ 4.38**	$ 4.22
Dividends paid per common share	**$ 2.20**	$ 2.00
Book value per common share	**$ 27.17**	$ 29.45
Net cash from operating activities	**$ 2,219**	$ 1,694

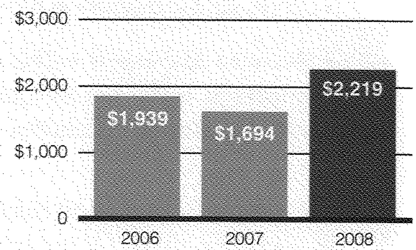
Basic Earnings Per Common Share

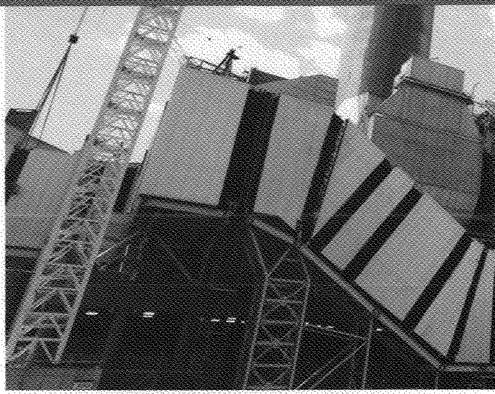


Dividends Paid Per Common Share

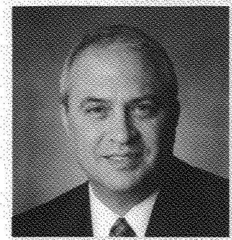


Net Cash from Operating Activities (millions)





Message to Shareholders



Anthony J. Alexander

Your Company achieved record results in 2008 despite the severe economic downturn. And, the steps we've been taking to further improve our performance should help us deal with current conditions and capitalize on future opportunities.

Key accomplishments included:

- Record earnings of $4.41 per share of common stock
- Near-record of $2.2 billion in cash generated from operations
- Record output of 82.4 million megawatt-hours (MWH) from our generating plants
- Continued improvement in transmission and distribution reliability
- Stipulated agreements in Ohio on a rate plan that would provide our customers with greater price certainty and our utilities with better opportunities to recover their costs

Also, we paid an increased dividend of $2.20 per share and exceeded the top end of our earnings guidance – notable achievements in a challenging year.

These and other accomplishments underscore our focus on the fundamentals, as well as our ongoing dedication to continuous improvement in every facet of our operations.

Meeting the Challenges of 2009 and Beyond

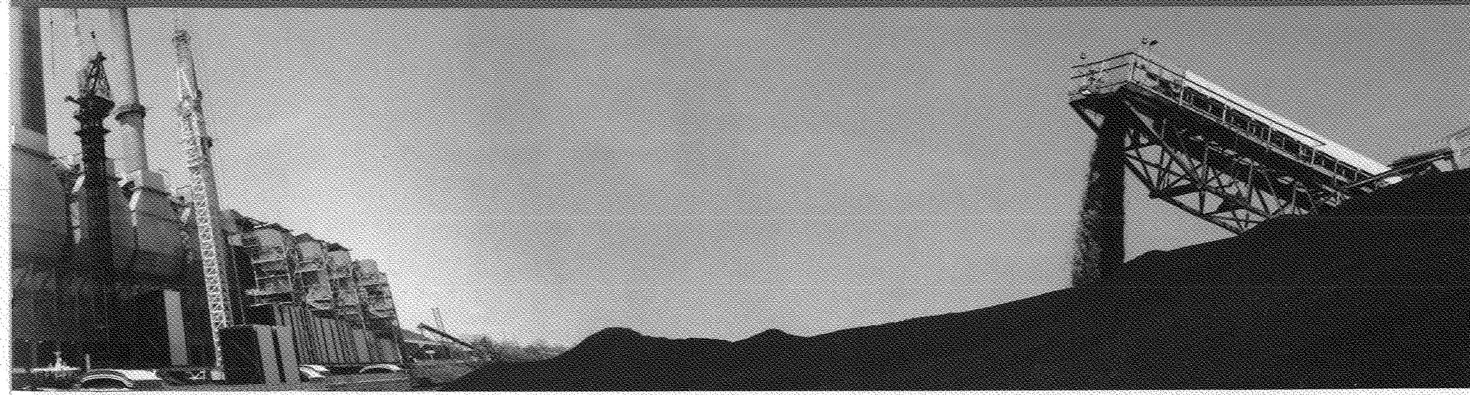
Our nation is in the midst of widespread economic turmoil. This is creating a number of challenges for our industry and our Company – from lower electricity sales to higher pension and financing costs.

We also expect more stringent environmental requirements over the next few years, which could include new mandates for carbon emissions designed to address the issue of global climate change.

We're responding to these challenges by making targeted reductions in capital and operating expenditures throughout the Company that will total more than $600 million in 2009 alone.

For example, we've delayed completion of the Fremont natural gas plant to better reflect current and projected power supply needs. And, we're reducing our near-term capital requirements through an adjusted construction schedule for the air quality compliance project at our Sammis Plant without affecting the completion deadline of December 31, 2010.

In addition, we've put into place a new organizational structure that will ensure more appropriate staffing levels and greater flexibility in meeting future challenges.



Maximizing the Value of Our Generating Fleet

The record performance of our nuclear fleet contributed to our total generation record of 82.4 million MWH. With recent uprates and a strong focus on operational excellence, our nuclear plants safely produced 32.2 million MWH, surpassing the previous record set in 2007 by nearly 6 percent. Also, the nuclear fleet's 92.6 percent capability factor – the amount of electricity generated compared with the amount that could be generated at full power for the year – set a new Company record.

Our fossil plants also contributed to the record total by producing 50.2 million MWH – a significant accomplishment considering scheduled outages earlier in the year at two of our largest generating units.

To achieve cost-effective, incremental growth of our generating capacity, we're installing advanced turbine technology and other state-of-the-art equipment at our plants. We added more than 50 megawatts (MW) of nuclear capacity through a turbine upgrade on Unit 2 at the Beaver Valley Power Station and through technology improvements at our Davis-Besse Nuclear Power Station. Also, we expect to add 100 MW of capacity to our Sammis Plant by 2010 with the completion of turbine upgrades on units 6 and 7. Over the last three years, we've improved our generating capability by nearly 500 MW through such uprates – at a fraction of the cost of a new power plant.

To further enhance our fossil operations, we made a strategic investment in a coal mine in Montana that is expected to improve plant output and environmental performance. Our $125 million equity investment in Signal Peak Energy should produce a fuel supply that offers the benefits of cleaner-burning western coal but with a higher heat value. Based on tests conducted in 2008, we expect the use of this higher-quality coal to add up to 170 MW of capacity to our fossil fleet while producing lower emissions of sulfur dioxide than our current mix of coals. Deliveries of Signal Peak coal are scheduled for later this year.

Transitioning to Competitive Markets

We remain focused on managing the transition to competitive markets for electricity in Ohio and Pennsylvania.

The Ohio Legislature enacted a new electric restructuring law last May. Throughout the legislative process, we aggressively represented the interests of our shareholders, employees and customers. The new law provides two options for pricing electricity in 2009 and beyond – through a rate plan that can set the total price for electricity, or a competitive bidding process that determines the price of generation only.

Last month, we reached agreements with key stakeholders – including organizations representing schools, hospitals and industrial and residential customers – on a comprehensive rate plan for our Ohio utilities. Under the plan, current base distribution rates would be frozen through December 31, 2011, and a competitive bidding process would set generation prices for customers who do not choose an alternative electricity supplier. If approved, the plan is expected to offer greater price certainty for our customers and more appropriate cost recovery for our utilities.

In Pennsylvania, all electric distribution companies are required to secure generation from competitive markets by 2011. A new law passed in 2008 outlines the procurement process and sets targets for energy efficiency and conservation. Customers in our Penn Power service area transitioned to the competitive generation market in 2007. And, later this year, we expect to begin arranging for generation that will be available to customers of our Met-Ed and Penelec companies in 2011.

To help customers prepare for this transition, Met-Ed and Penelec introduced a Voluntary Pre-payment Plan. It gives customers the opportunity to smooth out the impact of expected generation price increases by making modest, interest-earning pre-payments during the period before rate caps expire.

Customers of Jersey Central Power & Light have been receiving their generation supply through competitive markets since 2003, with prices set through periodic auctions.

In addition, we are currently developing compliance plans for energy efficiency and conservation mandates in all three states. We intend to introduce programs later this year that will help us meet these requirements while providing for recovery of related costs.

Enhancing Service to Customers

We continue to make strategic investments in our transmission and distribution system that are designed to achieve cost-effective improvements in the reliability of our service.

For example, we're investing in technologies to improve system maintenance and reduce the number and length of outages. These include advanced weather sensors near our substations to protect equipment; acoustical and temperature-sensitive devices that better predict equipment failures; and digital relays that provide real-time data on system conditions.

These and other efforts have helped reduce the average time customers have been without power in each of the last four years, for a total improvement of nearly 40 percent. In 2008, the average was just over two hours – approaching top quartile for our industry. And, the reliability of our transmission system is among the industry's best.

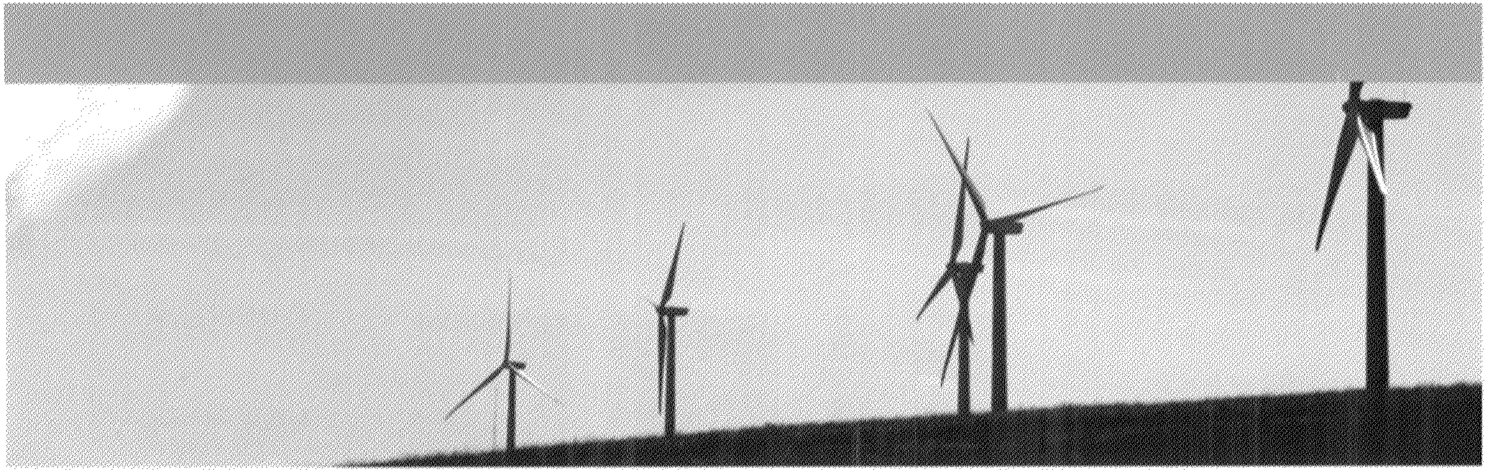
We've also improved the effectiveness of our storm response efforts. Following a hurricane-strength windstorm in September that interrupted electric service to more than one million customers in northern Ohio and western Pennsylvania, we responded with our largest-ever power restoration effort. It involved about 4,000 line, forestry and service workers from FirstEnergy companies and other utilities in the region. Our Contact Center representatives handled nearly 640,000 customer calls, and despite severe and widespread damage to our system, we restored service within 48 hours to nearly 90 percent of customers affected by the storm.

Along with hundreds of letters from customers thanking our crews, the Edison Electric Institute (EEI) honored us with its Emergency Recovery Award in recognition of our outstanding service restoration efforts following this storm. Also, for the third consecutive year, we received the EEI Emergency Assistance Award, which acknowledged the work of some 300 FirstEnergy employees who assisted utilities in Louisiana to restore service safely and efficiently in the aftermath of Hurricane Gustav.

Working Safely

In 2008, we attained near top-decile safety performance in our industry with an OSHA-recordable rate of 0.97, representing less than one recordable incident per 200,000 hours worked. Employees at 12 of our facilities had no recordable incidents last year, and our Davis-Besse employees have worked more than 9 million hours without a lost-time accident.

Despite these solid results, we won't be satisfied until we have no safety-related incidents. As part of our efforts to improve safety performance and accident prevention, our training emphasizes that employees are personally accountable for their safety and



responsible for full compliance with our safety programs and practices. Key to these efforts is the participation of union leaders who are taking an active role in safety assessments and other program components. With the consistent reinforcement of safety practices, we are working to achieve an accident-free workplace throughout our organization.

Protecting the Environment

We are committed to operating our facilities in an environmentally sound manner. Toward that end, 76 percent of the electricity we generated in 2008 came from low- or non-emitting sources. And, 40 percent of our output – from nuclear, wind and hydro sources – was carbon-free. As a result, emission rates for our power plants remain significantly lower than the regional average, providing us with a competitive advantage when meeting increasingly stringent environmental requirements.

In addition, later this year we expect to begin placing new environmental controls into service at our Sammis Plant. This massive construction project is approximately 85 percent complete, and we expect to have new controls on all seven units by the end of 2010.

We're further improving our environmental performance by adding new contracts for wind energy. We recently entered into long-term agreements to purchase 62.5 MW of wind energy generated in western Pennsylvania and 99 MW of wind power from a facility in central Illinois. With 376 MW of wind generation under contract, we're one of the largest providers of wind energy in the region.

Also, we are incorporating technologies across our system that help save energy and protect the environment. At our new West Akron Campus, a number of environmental features – including recycled building materials, drought-resistant landscaping and high-efficiency lighting with motion sensor controls – should help us achieve Leadership in Energy and Environmental Design (LEED) certification for the facility.

Building on Our Progress

Certainly, the economic crisis is troubling, but as I look back on the history of our Company, I'm reminded of the many times we have successfully overcome difficult challenges.

I am confident we will do so again by remaining focused on the fundamentals and continuing to deliver on our financial and operational goals.

I would like to acknowledge the efforts of our dedicated employees to make FirstEnergy one of our industry's top performers, and I thank you for your continued support.

Sincerely,

Anthony J. Alexander

Anthony J. Alexander
President and Chief Executive Officer

March 20, 2009

FirstEnergy Board of Directors

Dear Shareholders:

On behalf of your Board of Directors, let me congratulate FirstEnergy's management team and employees for achieving record results in 2008 while facing a difficult economy.

Over the past five years, our annualized total shareholder return of 10.3 percent, which reflects stock price appreciation plus reinvested dividends, ranks us ninth among the 57 member companies that comprise the Edison Electric Institute Index.

As FirstEnergy achieves key financial and operational milestones, your Board and management continue to uphold high standards of corporate governance and ethics to ensure shareholder interests are represented independently and thoughtfully. In fact, at the beginning of this year, our corporate governance practices ranked near top-decile for all utilities and outperformed 83 percent of all S&P 500 companies based on criteria developed by a leading independent provider of governance evaluations.

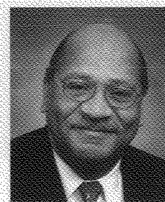
Although economic conditions remain challenging, your Board determined it was prudent to maintain the annual dividend rate of $2.20 per share in 2008. And, we will continue to consider your Company's prospects for future growth as we review the dividend on a quarterly basis, in keeping with Board policy.

We appreciate your support of FirstEnergy and remain committed to helping your management team enhance the value of your investment.

Sincerely,

George M Smart

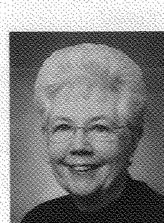
George M. Smart
Chairman of the Board



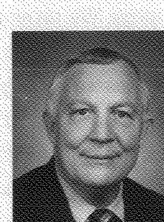
Paul T. Addison
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (Citigroup).

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

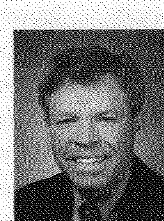
Michael J. Anderson
President and Chief Executive Officer of The Andersons, Inc.



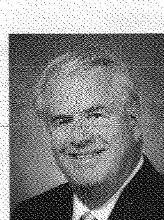
Dr. Carol A. Cartwright
President of Bowling Green State University. Retired President of Kent State University.



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

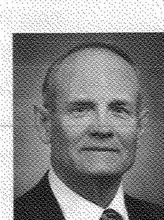


Robert B. Heisler, Jr.
Dean of the College of Business Administration and Graduate School of Management of Kent State University. Retired Chairman of the Board of KeyBank N.A.

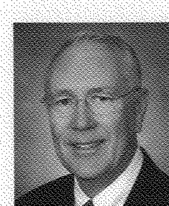


Ernest J. Novak, Jr.
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP.

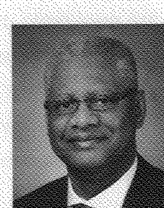
Catherine A. Rein
Retired, formerly Senior Executive Vice President and Chief Administrative Officer of MetLife, Inc.



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.

FirstEnergy Corp. Officers

Anthony J. Alexander
President and Chief Executive Officer

Mark T. Clark
Executive Vice President, Strategic Planning and Operations

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

Richard H. Marsh
Senior Vice President and Chief Financial Officer

James F. Pearson
Vice President and Treasurer

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

Rhonda S. Ferguson
Corporate Secretary

Lisa S. Wilson
Senior Assistant Controller

Paulette R. Chatman
Assistant Controller

Jacqueline S. Cooper
Assistant Corporate Secretary

Richard J. Horak
Assistant Controller

Jeffrey R. Kalata
Assistant Controller

Randy Scilla
Assistant Treasurer

Edward J. Udovich
Assistant Corporate Secretary

2008 Financial Report

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Glossary of Terms

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

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
Centerior	Centerior Energy Corporation, former parent of CEI and TE, which merged with OE to form FirstEnergy on November 8, 1997
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial and other corporate support services
FEV	FirstEnergy Ventures Corp., invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, former parent of several heating, ventilation, air conditioning and energy management companies
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	Met-Ed, Penelec and Penn
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shelf Registrants	OE, CEI, TE, JCP&L, Met-Ed and Penelec
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FirstEnergy Ventures Corp. and Boich Companies, that owns mining and coal transportation operations near Roundup, Montana, formerly known as Bull Mountain
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Waverly	The Waverly Power and Light Company, a wholly owned subsidiary of Penelec

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

ACO	Administrative Consent Order
AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP-Ohio	American Municipal Power - Ohio
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARB	Accounting Research Bulletin
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAT	Commercial Activity Tax
CBP	Competitive Bid Process
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge
DCPD	Deferred Compensation Plan for Outside Directors
DFI	Demand for information
DOE	United States Department of Energy
DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
EDCP	Executive Deferred Compensation Plan
EEI	Edison Electric Institute
EIS	Energy Independence Strategy
EITF	Emerging Issues Task Force
EITF 08-6	Equity Method Investment Accounting Considerations
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ESP	Electric Security Plan
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109"
FirstCom	First Communications, Inc.
FMB	First Mortgage Bond
FSP	FASB Staff Position
FSP SFAS 115-1 and SFAS 124-1	FSP SFAS 115-1 and SFAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"
FTR	Financial Transmission Rights
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
HVAC	Heating, Ventilation and Air-conditioning

IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-emitting Diode
LIBOR	London Interbank Offered Rate
LOC	Letter of Credit
LTIP	Long-term Incentive Program
MEW	Mission Energy Westside, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOV	Notice of Violation
NO_x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCA	Office of Consumer Advocate
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OTC	Over the Counter
OVEC	Ohio Valley Electric Corporation
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PSA	Power Supply Agreement
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
RECB	Regional Expansion Criteria and Benefits
RFP	Request for Proposal
RSP	Rate Stabilization Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
S&P 500	Standard & Poor's Index of Widely Held Common Stocks
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 107	SFAS No. 107, "Disclosure about Fair Value of Financial Instruments"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 132(R)-1	SFAS No. 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141(R)	SFAS No. 141(R), "Business Combinations"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115"
SFAS 160	SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"
SFAS 161	SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133"
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VIE	Variable Interest Entity

The following selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, the sections entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with our consolidated financial statements and the "Notes to Consolidated Financial Statements." Our Consolidated Statements of Income are not necessarily indicative of future conditions or results of operations.

FIRSTENERGY CORP.

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2008	2007	2006	2005	2004
		(In millions, except per share amounts)			
Revenues	$ 13,627	$ 12,802	$ 11,501	$ 11,358	$ 11,600
Income From Continuing Operations	$ 1,342	$ 1,309	$ 1,258	$ 879	$ 907
Net Income	$ 1,342	$ 1,309	$ 1,254	$ 861	$ 878
Basic Earnings per Share of Common Stock:					
Income from continuing operations	$ 4.41	$ 4.27	$ 3.85	$ 2.68	$ 2.77
Net earnings per basic share	$ 4.41	$ 4.27	$ 3.84	$ 2.62	$ 2.68
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	$ 4.38	$ 4.22	$ 3.82	$ 2.67	$ 2.76
Net earnings per diluted share	$ 4.38	$ 4.22	$ 3.81	$ 2.61	$ 2.67
Dividends Declared per Share of Common Stock (1)	$ 2.20	$ 2.05	$ 1.85	$ 1.705	$ 1.9125
Total Assets	$ 33,521	$ 32,311	$ 31,196	$ 31,841	$ 31,035
Capitalization as of December 31:					
Common Stockholders' Equity	$ 8,283	$ 8,977	$ 9,035	$ 9,188	$ 8,590
Preferred Stock	-	-	-	184	335
Long-Term Debt and Other Long-Term Obligations	9,100	8,869	8,535	8,155	10,013
Total Capitalization	$ 17,383	$ 17,846	$ 17,570	$ 17,527	$ 18,938
Weighted Average Number of Basic Shares Outstanding	304	306	324	328	327
Weighted Average Number of Diluted Shares Outstanding	307	310	327	330	329

(1) Dividends declared in 2008 include four quarterly dividends of $0.55 per share. Dividends declared in 2007 include three quarterly payments of $0.50 per share in 2007 and one quarterly payment of $0.55 per share in 2008. Dividends declared in 2006 include three quarterly payments of $0.45 per share in 2006 and one quarterly payment of $0.50 per share in 2007. Dividends declared in 2005 include two quarterly payments of $0.4125 per share in 2005, one quarterly payment of $0.43 per share in 2005 and one quarterly payment of $0.45 per share in 2006. Dividends declared in 2004 include four quarterly dividends of $0.375 per share paid in 2004 and a quarterly dividend of $0.4125 per share paid in 2005.

PRICE RANGE OF COMMON STOCK

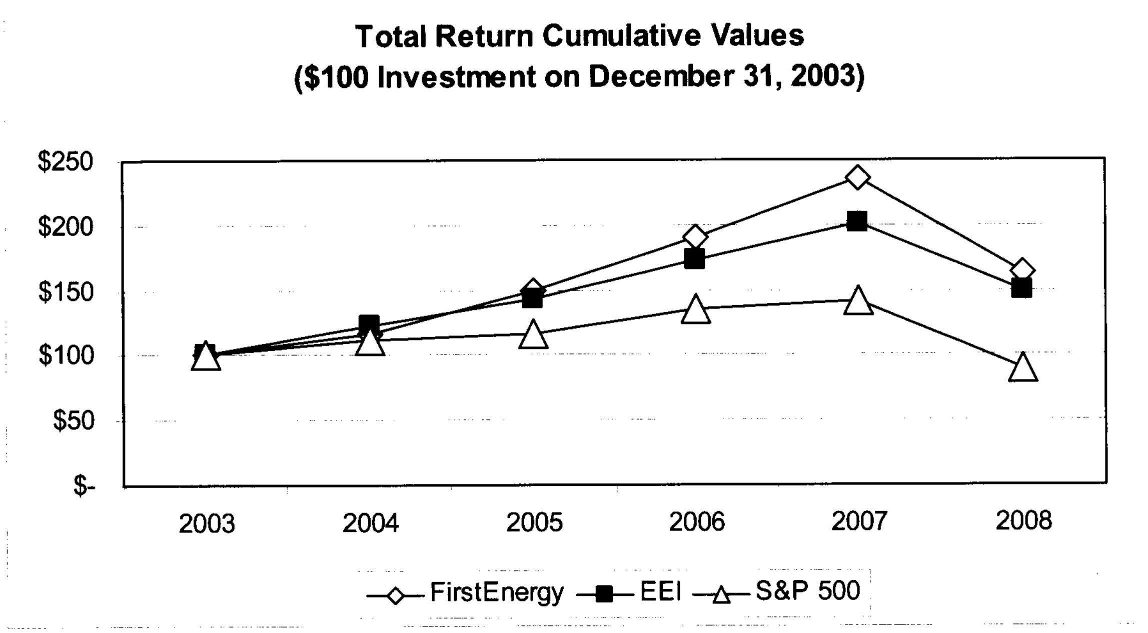
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2008		2007	
First Quarter High-Low	$ 78.51	$ 64.44	$ 67.11	$ 57.77
Second Quarter High-Low	$ 83.49	$ 69.20	$ 72.90	$ 62.56
Third Quarter High-Low	$ 84.00	$ 63.03	$ 68.31	$ 58.75
Fourth Quarter High-Low	$ 66.69	$ 41.20	$ 74.98	$ 63.39
Yearly High-Low	$ 84.00	$ 41.20	$ 74.98	$ 57.77

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2003 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 115,151 and 114,871 holders of 304,835,407 shares of FirstEnergy's common stock as of December 31, 2008 and January 31, 2009, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11(A) to the consolidated financial statements.

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 discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding our management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to the speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Ohio and Pennsylvania, the impact of the PUCO's regulatory process on the Ohio Companies associated with the ESP and MRO filings, including any resultant mechanism under which the Ohio Companies may not fully recover costs (including, but not limited to, the costs of generation supply procured by the Ohio Companies, Regulatory Transition Charges and fuel charges), or the outcome of any competitive generation procurement process in Ohio, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices and availability, replacement power costs being higher than anticipated or inadequately hedged, the continued ability of our regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, other legislative and regulatory changes, revised environmental requirements, including possible greenhouse gas emission regulations, the potential impacts of the U.S. Court of Appeals' July 11, 2008 decision requiring revisions to the CAIR rules and the scope of any laws, rules or regulations that may ultimately take their place, the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the AQC Plan (including that such amounts could be higher than anticipated or that certain generating units may need to be shut down) or levels of emission reductions related to the Consent Decree resolving the NSR litigation or other potential regulatory initiatives, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC (including, but not limited to, the Demand for Information issued to FENOC on May 14, 2007), the timing and outcome of various proceedings before the PUCO (including, but not limited to the distribution rate cases and the generation supply plan filing for the Ohio Companies and the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the RSP and the RCP, including the recovery of deferred fuel costs), Met-Ed's and Penelec's transmission service charge filings with the PPUC, the continuing availability of generating units and their ability to operate at or near full capacity, the ability to comply with applicable state and federal reliability standards, the ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the ability to improve electric commodity margins and to experience growth in the distribution business, the changing market conditions that could affect the value of assets held in our nuclear decommissioning trusts, pension trusts and other trust funds, and cause us to make additional contributions sooner, or in an amount that is larger than currently anticipated, the ability to access the public securities and other capital and credit markets in accordance with our financing plan and the cost of such capital, changes in general economic conditions affecting us, the state of the capital and credit markets affecting us, interest rates and any actions taken by credit rating agencies that could negatively affect our access to financing or its costs and increase our requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees, the continuing decline of the national and regional economy and its impact on our major industrial and commercial customers, issues concerning the soundness of financial institutions and counterparties with which we do business, and the risks and other factors discussed from time to time in our SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for our management to predict all such factors, nor assess the impact of any such factor on our business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.*

EXECUTIVE SUMMARY

Net income in 2008 was $1.34 billion, or basic earnings of $4.41 per share of common stock ($4.38 diluted), compared with net income of $1.31 billion, or basic earnings of $4.27 per share ($4.22 diluted), in 2007 and $1.25 billion, or basic earnings of $3.84 per share ($3.81 diluted), in 2006.

Change in Basic Earnings Per Share From Prior Year	2008	2007
Basic Earnings Per Share – Prior Year	$ 4.27	$ 3.84
Gain on non-core asset sales – 2008/2007	0.02	0.04
Litigation settlement – 2008	0.03	-
Trust securities impairment	(0.20)	(0.03)
Saxton decommissioning regulatory asset – 2007	(0.05)	0.05
PPUC NUG accounting adjustment – 2006	-	0.02
Revenues	1.61	2.51
Fuel and purchased power	(1.24)	(1.51)
Amortization of regulatory assets	(0.07)	(0.31)
Deferral of new regulatory assets	(0.37)	-
Investment income	0.08	(0.03)
Interest expense	0.04	(0.11)
Reduced common shares outstanding	0.03	0.22
Other expenses	0.26	(0.42)
Basic Earnings Per Share	$ 4.41	$ 4.27

Financial Matters

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations. We have access to more than $4 billion of liquidity, of which approximately $2.6 billion was undrawn as of January 31, 2009. During 2009 and in subsequent years, we expect to satisfy our obligations with a combination of cash from operations and funds from the capital markets. Since the middle of October 2008, our subsidiaries have issued $1.2 billion of long-term debt securities in the capital markets (see Long-Term Financings below). We also expect that borrowing capacity under our existing credit facilities will continue to be available to manage our working capital requirements. In response to the current economic climate, we have taken several steps to strengthen our liquidity position and provide additional financial flexibility (see Strategy and Outlook).

Acquisition of Additional Equity Interests in the Perry Plant and Beaver Valley Unit 2

In May 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant. In June 2008, NGC purchased approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2 and 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The aggregate purchase price for NGC's acquisition of these lessor equity interests was approximately $438 million. The Ohio Companies continue to lease these MW under the respective sale and leaseback arrangements and the related lease debt remains outstanding.

Non-Core Asset Sale

On March 7, 2008, we sold substantially all of the assets of FirstEnergy Telecom Services, Inc. to FirstCom for $45 million in cash, with FirstCom assuming related liabilities. The sale resulted in an after-tax gain of approximately $0.06 per share. We are a 15.6% shareholder in FirstCom.

New Credit Facilities

In May 2008, we, along with FES, entered into a new $300 million, 364-day revolving credit facility with the Royal Bank of Scotland PLC. The pricing, terms and conditions are substantially similar to those contained in our current $2.75 billion revolving credit agreement.

In response to recent turmoil in the credit markets, we, along with FES and FGCO, entered into a new $300 million secured term loan facility with Credit Suisse in October 2008. Under the facility, FGCO is the borrower and we, along with FES, are guarantors. Generally, the facility is available to FGCO until October 7, 2009, with a minimum borrowing amount of $100 million and a maturity of 30 days from the date of the borrowing. This facility is currently unused.

Long-Term Financings

In September 2008, we, along with the Shelf Registrants, filed an automatically effective shelf registration statement with the SEC. The shelf registration provides us the flexibility to issue and sell various types of securities, including common stock, preferred stock, debt securities, warrants, share purchase contracts, and share purchase units. The Shelf Registrants may utilize the shelf registration to offer and sell unsecured, and in some cases, secured debt securities. The following securities have been issued and sold under the shelf registration to date:

- OE – $275 million of 8.25% Series of FMBs due 2038 issued on October 20, 2008;
- OE – $25 million of 8.25% Series of FMBs due 2018 issued on October 20, 2008;
- CEI – $300 million of 8.875% Series of FMBs due 2018 issued on November 18, 2008;
- Met-Ed – $300 million of 7.70% Senior Notes due 2019 issued on January 20, 2009; and
- JCP&L – $300 million of 7.35% Senior Notes due 2019 issued on January 27, 2009.

Rating Agency Action

On August 1, 2008, S&P changed its outlook for FirstEnergy and our subsidiaries from "negative" to "stable." On November 5, 2008, S&P raised its senior unsecured rating on OE, Penn, CEI and TE to BBB from BBB-. Moody's outlook for FirstEnergy and our subsidiaries remains "stable."

Regulatory Matters – Ohio

Ohio Legislative Process

On May 1, 2008, the Governor of Ohio signed SB221 into law, which became effective July 31, 2008. The bill requires all electric distribution utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility could also file an MRO in which it would have to demonstrate the following objective market criteria: the utility or its transmission service affiliate belongs to a FERC-approved RTO having a market-monitor function and the ability to take actions to identify and mitigate market power, and a published source of information is available publicly through a subscription that identifies pricing information for traded electricity and energy products that are contracted for delivery two years into the future.

Ohio Regulatory Proceedings

On July 31, 2008, our Ohio Companies filed both an ESP and an MRO with the PUCO. The comprehensive ESP included supply and pricing for retail generation service for up to a three-year period, in addition to seeking approval of outstanding issues pending before the PUCO in the Ohio Companies' distribution rate case and application to recover 2006-2007 deferred fuel costs. The MRO filing outlined a CBP for providing retail generation supply if the ESP was not implemented.

On November 25, 2008, the PUCO issued an order denying the MRO and on December 19, 2008, the PUCO approved the ESP, with substantial modifications. On December 22, 2008, the Ohio Companies filed an application for rehearing of the MRO and withdrew their application for the ESP, as allowed under Ohio law. The Ohio Companies cited that the ESP, as modified by the PUCO, no longer maintained a reasonable balance between rate stability for customers and a fair return on the Ohio Companies' investments to serve customers. The Ohio Companies also notified the PUCO of their intent to maintain current tariff rates as of January 1, 2009, as provided for under SB221.

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

On January 7, 2009, the PUCO ordered the Ohio Companies to file revised tariffs by January 12, 2009, reflecting the termination of OE's and TE's RTC as well as the termination of fuel recovery riders for each of the Ohio Companies, to be effective retroactive to January 1, 2009, on a service rendered basis. On January 9, 2009, the Ohio Companies filed a Motion to Stay to delay the effective date of the January 7, 2009 order in its entirety until the resolution of any appeal of the order. In addition, the Ohio Companies requested a fuel rider, proposing to recover the difference between costs incurred by the Ohio Companies to purchase power and the generation charges paid by their customers during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO temporarily approved the fuel rider, subject to a future prudence review. The PUCO also issued an Entry requiring the Ohio Companies to concurrently implement the original January 7, 2009 order.

On January 21, 2009, the PUCO granted the Ohio Companies' application for an increase in distribution rates in the amount of $137 million, as well as the application for rehearing to allow further consideration of the MRO filing. On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing on part of the issues to begin on February 25, 2009, and a second hearing on the remainder of the provisions of the overall Stipulated ESP on March 11, 2009.

Regulatory Matters - Pennsylvania

Pennsylvania Legislative Process

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

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;

- the competitive procurement process must be approved by the PPUC and may include auctions, requests for proposal, and/or bilateral agreements;

- utilities must provide for the installation of smart meter technology within 15 years;

- a minimum reduction in peak demand of 4.5% by May 31, 2013;

- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and

- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Pennsylvania Regulatory Proceedings

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

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

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

Regulatory Matters – New Jersey

New Jersey Energy Master Plan

On October 22, 2008, the Governor of New Jersey released the details of New Jersey's EMP, which includes goals to reduce energy consumption by a minimum of 20% by 2020, reduce peak demand by 5,700 MW by 2020, meet 30% of the state's electricity needs with renewable energy by 2020, and examine smart grid technology. The EMP outlines a series of goals and action items to meet set targets, while also continuing to develop the clean energy industry in New Jersey. The Governor will establish a State Energy Council to implement the recommendations outlined in the plan.

New Jersey Economic Assistance and Recovery Plan

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

Solar Renewable Energy

On September 30, 2008, JCP&L filed a proposal in response to an NJBPU directive addressing solar project development in the State of New Jersey. Under the proposal, JCP&L would enter into long-term agreements to buy and sell Solar Renewable Energy Certificates (SREC) to provide a stable basis for financing solar generation projects. An SREC represents the solar energy attributes of one megawatt-hour of generation from a solar generation facility that has been certified by the NJBPU Office of Clean Energy. Under this proposal JCP&L would solicit SRECs to satisfy approximately 60%, 50%, and 40% of the incremental SREC purchases needed in its service territory through 2010, 2011 and 2012, respectively, to meet the Renewable Portfolio Standards adopted by the NJBPU in 2006. A schedule for further NJBPU proceedings has not yet been established.

Operational Matters

Record Generation Output

We set a new generation output record of 82.4 billion kilowatt-hours during 2008, an increase over the previous record of 82.0 billion kilowatt-hours established in 2006. This generation record reflects an annual all-time high for our nuclear fleet, which set a new generation output record of 32.2 billion kilowatt-hours during 2008, a 6% increase over the previous record established in 2007.

Wind Power Contract

On December 23, 2008, FES purchased a 17-year contract from Constellation Energy for the procurement of 99 MW of wind power from Twin Groves Wind Farm in Illinois. This purchase expands FES' renewable energy portfolio and brings its total wind power capacity under contract to 376 MW.

Fremont Plant

In January 2008, FGCO acquired a partially complete 707-MW natural gas fired generating plant in Fremont, Ohio from Calpine Corporation for $253.6 million. FGCO completed an engineering study in June 2008, indicating an estimated additional $208 million of capital expenditures will be required to complete the project. Approximately $41 million of the incremental capital was invested in 2008. In December 2008, the construction schedule was extended to better reflect current and projected power supply needs; the plant is now expected to be brought on line in 2012. Original plans called for completion of the plant by 2010. The original estimate of $208 million to complete the plant may be revised as a result of the new construction schedule.

Refueling Outages

On February 14, 2008, Davis-Besse returned to service following completion of its scheduled refueling outage, which began on December 30, 2007. In addition to replacing 76 of the 177 fuel assemblies, several improvement projects were completed, including rewinding the turbine generator and reinforcing welds on plant equipment.

On May 22, 2008, Beaver Valley Unit 2 returned to service following its regularly scheduled refueling outage. Major work activities completed during the outage included replacing approximately one-third of the fuel assemblies in the reactor, replacing the high pressure turbine rotor and inspecting the reactor vessel and other plant safety systems. During the refueling outage, the final phase of an extended power uprate project was also completed. Beaver Valley Unit 2 had operated for 520 consecutive days when it was taken off line for the outage.

New Long-Term Fuel Supply Arrangements

On July 16, 2008, FEV entered into a joint venture with the Boich Companies, a Columbus, Ohio-based coal company, to acquire a majority stake in the Bull Mountain Mine Operations, now called Signal Peak, near Roundup, Montana. This transaction is part of our strategy to secure high-quality fuel supplies at attractive prices to maximize the capacity of our existing fossil generating plants. The joint venture acquired 80 percent of the mining operations and 100 percent of the transportation operations, with FEV owning a 45 percent economic interest and an affiliate of the Boich Companies owning a 55 percent economic interest in the joint venture; both parties have a 50 percent voting interest in the joint venture. In a related transaction, we entered into a 15-year agreement to purchase up to 10 million tons of bituminous western coal annually from the mine. We also entered into agreements with the rail carriers associated with transporting coal from the mine to our generating stations, and expect to begin taking delivery of the coal in late 2009. The joint venture has the right to resell Signal Peak coal tonnage not used at our facilities and has call rights on such coal above certain levels.

September Windstorm

On September 14, 2008, the remnants of Hurricane Ike swept through Ohio and western Pennsylvania and produced unexpectedly high winds, reaching nearly 80 mph. More than one million customers of OE, CEI, Penn and Penelec were affected by the windstorm, which produced the largest storm-related outage in the history of any of those companies. Storm costs totaled approximately $43 million, of which $24 million was recognized as capital and $19 million as O&M expense.

R.E. Burger Plant

On December 30, 2008, we filed a motion with the U.S. District Court for the Southern District of Ohio, requesting an additional 105 days to decide whether to install scrubbers and other environmental equipment for two 156 MW coal fired units at our R.E. Burger Plant, repower the units, or to shut them down in the next two years. Under the terms of a consent decree related to the 2005 NSR settlement, we were required to make a decision by December 31, 2008. On January 30, 2009, the Court granted us an extension until March 31, 2009, to make our decision.

FIRSTENERGY'S BUSINESS

We are a diversified energy company headquartered in Akron, Ohio, that operates primarily through three core business segments (see "Results of Operations").

- **Energy Delivery Services** transmits and distributes electricity through our eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its PLR and default service requirements in Pennsylvania and New Jersey. This business segment derives its revenues principally from the delivery of electricity within our service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Pennsylvania and New Jersey franchise areas.

  The service areas of our utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,040,000
Penn	Western Pennsylvania	160,000
CEI	Northeastern Ohio	755,000
TE	Northwestern Ohio	312,000
JCP&L	Northern, Western and East Central New Jersey	1,093,000
Met-Ed	Eastern Pennsylvania	549,000
Penelec	Western Pennsylvania	590,000
ATSI	Service areas of OE, Penn, CEI and TE	

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

- **Ohio Transitional Generation Services** supplies the electric power needs of non-shopping customers under the default service requirements of our Ohio Companies. The segment's net income is primarily derived from electric generation sales revenues less the cost of power purchased from the competitive energy services segment through a full-requirements PSA arrangement with FES (through December 31, 2008), including net transmission and ancillary costs charged by MISO to deliver energy to retail customers.

Other operating segments include HVAC services (divestiture completed in 2006) and telecommunication services. We have substantially completed the divestiture of our non-core businesses (see Note 8 to the consolidated financial statements). The assets and revenues for the other business operations are below the quantifiable threshold for separate disclosure as "reportable operating segments."

STRATEGY AND OUTLOOK

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

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

Despite the recent global financial crisis and ongoing U.S. recession, our strategy remains intact. Our focus, however, has shifted in the near term as we respond to these events by identifying and implementing reasoned adjustments to our current plans. Following appropriate reviews, we have reduced our operational and capital spending plans and adjusted our financing plans for 2009-2011. Near-term, we expect to see a continued decline in sales due to the current recessionary environment, primarily in the industrial sector. Sales in 2009 are projected to be relatively flat compared with 2008.

Our gradual progression to competitive generation markets across our tri-state service territory and other strategies to improve performance and deliver consistent financial results is characterized by several important transition periods:

2005 to 2006

In 2005 and 2006, our efforts included preparing for competitive generation markets by improving the operational performance of our generating fleet and the reliability of our transmission and distribution system. The transfer of ownership of our generating assets in 2005 from the Ohio Companies and Penn to subsidiaries of FES, our competitive generation subsidiary, was key to preparing for market competition. With the previous divestiture of generation assets by JCP&L, Met-Ed and Penelec, and JCP&L's transition to competitive generation markets through the New Jersey BGS auction, we gained experience in producing and acquiring competitively priced electricity for customers while delivering a fair return to shareholders. We expect to utilize this experience as we continue to transition to competitive generation markets in Ohio and Pennsylvania.

To facilitate an equitable transition to competitive generation markets, we developed and received approval from the PUCO for an RSP that, along with the RCP, provided our customers in Ohio with reliable generation supply and price stability from 2006 through 2008.

2007 to 2008

Effective January 1, 2007, we successfully transitioned Penn to market-based retail rates for generation service through a competitive, wholesale power supply procurement process. During that year we also completed comprehensive rate cases for Met-Ed and Penelec, which better aligned their transmission and distribution rates with their rate base and costs to serve customers. Met-Ed and Penelec were unsuccessful in securing approval from the PPUC for generation rate increases. As a result, FES expects to continue to provide Met-Ed and Penelec with partial requirements for their PLR and default service load at below-market prices through the end of 2010 when their current rate caps expire.

Our transition to competitive generation markets was supported by continued strong operational results in 2008 led by generation output of 82.4 billion KWH. During the year, the net-demonstrated capacity at several of our units increased through cost-effective unit upgrades as part of our "asset mining" strategy. In addition, we made plant improvements that eliminated the impact of 149 MW of seasonal reductions in generating output caused by elevated summer temperature conditions on our peaking units. We also signed additional long-term contracts to purchase output from wind generators, making FES the largest wind provider in Pennsylvania and bringing our total renewable wind portfolio to 376 MW.

We made several strategic investments in 2008, including the purchase of the partially complete Fremont Plant, which is expected to begin commercial operation in 2012. The addition of this plant complements our existing fleet, giving us the option to dispatch in either MISO or PJM. Additionally, we entered into a joint venture to acquire a majority stake in the Signal Peak coal mining project. As part of that transaction, we also entered into a 15-year agreement to purchase up to 10 million tons of coal annually from the mine, securing a long-term western fuel supply at attractive prices. The higher Btu content of Signal Peak coal versus Powder River Basin coal is expected to help avoid fossil plant derates of approximately 170 to 200 MW, and helps support our incremental generation expansion plans. In the fourth quarter of 2008, FES assigned two existing Powder River Basin contracts to a third party in order to reduce its forecasted 2010 long coal position as a result of expected deliveries from Signal Peak.

In July 2008, we filed a comprehensive ESP with the PUCO that offered modest increases for customers in Ohio of approximately five percent annually through 2011. We concurrently filed an MRO, another option allowed under Ohio's energy law, which proposed a competitive bidding process for procuring electricity for Ohio customers. In November 2008, the PUCO issued an order denying our MRO. In December 2008, the PUCO approved, but substantially modified, our ESP. After determining that the plan no longer maintained a reasonable balance between providing customers with continued rate stability and a fair return on the Ohio Companies' investments to serve customers, we withdrew our application for the ESP as allowed by law (see Regulatory Matters – Ohio).

In late December 2008, our Ohio Companies conducted a competitive bidding process, using an RFP format managed by an independent third-party, for the procurement of electric generation for retail customers from January 5 through March 31, 2009. Four qualified wholesale bidders were selected for 97% of the available tranches up for bid, including FES, which was the successful bidder for 75 of the available tranches up for bid. Each tranche equals approximately 1% of the total load of the Ohio Companies. Approximately 50% of FES' estimated electric sales for the first quarter of 2009 are expected to be supplied under this agreement.

2009 to 2010

Earnings guidance for 2009 will be released following regulatory clarity in Ohio with respect to either an ESP or MRO. Higher pension and fuel costs, coupled with the elimination of deferral accounting for distribution-related operating expenses, are expected to negatively impact earnings. Expected drivers of 2009 earnings are discussed more fully below under "Financial Outlook."

Distribution rate increases went into effect for OE and TE in January 2009, and will go into effect for CEI in May 2009, as a result of rate cases filed in 2007. Transition cost amortization related to the Ohio Companies' rate plans ended for OE and TE on December 31, 2008.

As provided for under SB221, our Ohio Companies initially maintained 2008 tariffs for Ohio retail customers, pending approval of either an ESP or MRO, with plans to use continued OE and TE RTC recovery to reduce previously deferred costs. However, the PUCO issued an Order in January 2009, denying continued recovery of OE and TE RTC and fuel riders for all three Ohio Companies. In response, we filed an application for a fuel rider in order to recover the difference between costs incurred by the Ohio Companies to purchase power and the generation charges paid by their customers during the period January 1, 2009 through March 31, 2009. The PUCO temporarily approved the fuel rider, subject to a future prudence review. On February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which the PUCO attorney examiner set for a hearing to begin on February 25, 2009 (see Regulatory Matters – Ohio).

Financial results for 2009 and beyond will be affected by either an ESP or MRO ultimately being approved by the PUCO. Under the results of either an MRO or a CBP within an ESP, FES ultimately may serve only a portion of the Ohio Companies' retail generation needs, resulting in excess generation available for other wholesale or competitive market retail sales. These and other uncertainties will exist until a new Standard Service Offer is approved by the PUCO and a CBP for Ohio customers is completed. A subsequent CBP may be conducted to meet customer supply needs beyond March 31, 2009, or until either an ESP or MRO is approved by the PUCO for the Ohio Companies. Price uncertainty inherent in competitive markets exists in any CBP.

In Pennsylvania, the scheduled termination at the beginning of 2009 of a favorably-priced third-party supply contract serving Met-Ed and Penelec default service customers will also negatively affect earnings. Currently, FES is obligated to supply an estimated additional 4.5 billion KWH from its supply portfolio under the existing contract with Met-Ed and Penelec. However, because retail generation rates for Met-Ed and Penelec remain frozen at a level below current market prices through the end of 2010, FES may incur a related opportunity cost in 2009 and 2010, since it will be unable to sell this power at market prices.

As we look ahead to 2009 and beyond, we expect to continue our focus on operational excellence with an emphasis on continuous improvement in our core businesses to position for success in the next market transition phase. This includes ongoing incremental investment in projects to increase our generation capacity and energy production capability as well as programs to continue to improve transmission and distribution system reliability and customer service.

2011 and Beyond

Another major transition period for FirstEnergy will begin in 2011 as the current cap on Met-Ed's and Penelec's retail generation rates is scheduled to expire. Beginning in 2011, Met-Ed and Penelec expect to obtain their power supply from the competitive wholesale market and fully recover their costs through retail rates. In February 2009, Met-Ed and Penelec filed with the PPUC a generation procurement proposal for obtaining their power supply in 2011 and beyond. Assuming approval of this plan, we expect FES to redeploy the power currently sold to Met-Ed and Penelec to the wholesale market.

We will continue to be actively engaged in the regulatory process in Ohio and Pennsylvania as we manage the final transition to competitive generation markets. We also plan to continue our efforts to extract additional production capability from existing generating plants as discussed under "Capital Expenditures Outlook" below and maintain the financial and strategic flexibility necessary to move through this transition.

Financial Outlook

In response to the recent unprecedented volatility in the capital and credit markets, we continue to assess our exposure to counterparty credit risk, our access to funds in the capital and credit markets, and market-related changes in the value of our postretirement benefit trusts, nuclear decommissioning trusts and other investments. We have taken several steps to strengthen our liquidity position and provide additional flexibility to meet our anticipated obligations and those of our subsidiaries. These actions include:

- spending reductions of more than $600 million compared to 2008 levels through appropriate changes in capital and operating and maintenance expenditures;
- delaying completion of the Fremont natural gas plant to better reflect current and projected power supply needs; and
- adjusting the construction schedule for the $1.7 billion AQC project at our W.H. Sammis Plant in order to defer certain costs from our 2009 budget; we continue to expect to meet our completion deadline by the end of 2010.

Despite the recent financial crisis and ongoing U.S. recession, our financial strategy remains intact and is focused on delivering consistent financial results, improving financial strength and flexibility, optimizing cash flows to benefit investors, and maintaining our current investment-grade ratings.

The following summary of earnings drivers does not include the potential effects of the PUCO approving either the Amended Application containing the proposed Stipulated ESP or an MRO that may be implemented in Ohio.

Positive earnings drivers in 2009 are expected to include:

- increased FES generation margin from Ohio customers from generation supply during the first quarter as a result of the RFP competitive bidding process;
- decreased Ohio transition cost amortization (a non-cash item), reflecting the expiration of RTC for OE and TE in December 2008, partially offset by increased RTC amortization for CEI;
- improvements to operations and maintenance cost management, including staffing adjustments, changes in our compensation structure, fossil plant outage schedule changes and general cost-saving measures; and
- a distribution rate increase in Ohio.

Negative earnings drivers in 2009 are expected to include:

- decreased generation output, three nuclear refueling outages in 2009 compared to two in 2008 and a continued increase in fuel expense;
- lower wholesale market prices for electricity;
- the expiration of a favorable third-party power supply contract for Met-Ed and Penelec;
- increased pension costs related to 2008 market declines;

- elimination of the OE and TE RTC, and a reduction in CEI RTC revenues;
- increased depreciation and general taxes;
- the elimination of deferred distribution operating costs in Ohio; and
- reduced customer loads, particularly in the industrial sector.

Despite significant declines in the value of our pension plan investments, we currently estimate that contributions to the plan will not be required in 2009 or 2010. The overall actual investment return as of December 31, 2008 was a loss of 23.8% versus an assumed 9% return for the year. Based on a 7.0% discount rate, our 2009 pension and OPEB expense is expected to increase by $230 million.

Our liquidity position remains strong, with access to more than $4 billion of liquidity, of which approximately $2.6 billion was available as of January 31, 2009. We intend to continue to fund our capital requirements though our projected cash flow from operations as well as from long-term debt issuances as capital market conditions warrant.

A driver for longer-term earnings growth is our continued effort to improve the utilization and output of our generation fleet. We are also expecting timely recovery of costs and capital investments in our regulated business. We plan to invest approximately $4 billion in our regulated energy delivery services business during the 2009-2013 period and to pursue timely recovery of those costs in rates. We also expect rising prices for fuel, purchased power and other operating costs to continue during this period.

Capital Expenditures Outlook

We have reduced our capital expenditures forecast to reflect the current economic climate. Our capital expenditures forecast for 2009-2013 is approximately $8.1 billion. Approximately $506 million of this relates to AQC projects discussed under "Environmental Outlook" below. Annual expenditures for this program reached their peak in 2008, totaling $638 million. AQC expenditures are expected to decline in 2009 to approximately $414 million and by the end of 2010, we expect the program to be complete.

With respect to the remainder of our business, we anticipate average annual capital expenditures of approximately $1.4 billion from 2009 through 2013. Distribution and transmission projects are expected to average approximately $783 million per year over the next five years. Over that same period, annual expenditures for our competitive energy services business are expected to be lower in 2009 than 2008 as a result of lower AQC expenditures and reduced overall capital spending plans in response to the current economic climate.

Compared to the construction of new base-load generation assets, we believe our strategy of making incremental additions and operational improvements to our generating fleet to improve output and reliability provides several advantages including: lower capital costs; reduced technological risks; decreased risk of project cost overruns; and an accelerated time to market for the additional output.

Major capital investments planned at our nuclear plants during 2009 to 2013 include approximately $375 million for replacement of the steam generator at Davis-Besse. While this project is not expected to be completed until 2014, fabrication of some equipment will begin in 2009. We also anticipate spending associated with the replacement of the steam generator at Beaver Valley Unit 2, replacement of the low pressure turbines at Beaver Valley and Perry, and other capital projects to total approximately $351 million. Combined, these expenditures represent approximately $1.1 billion of increased capital over a typical maintenance level for nuclear generation during the 2009 to 2013 period.

Projected non-AQC capital spending for 2009 and, on average, for each of the years in the 2010 to 2013 period are as follows:

Projected Non-AQC Capital Spending by Business Unit	**2009**	**2010 to 2013 Per Year Average**
	(In millions)	
Energy Delivery	$ 701	$ 804
Nuclear	260	354
Fossil	219	255
Corporate & Other	58	116
Non-AQC Capital Spending	$ 1,238	$ 1,529

Projected capital expenditures for our AQC plan for 2009 and 2010, and the change in annual spending, are as follows:

Projected AQC Capital Spending	2009	2010
	(In millions)	
AQC*	$ 414	$ 92
Change from Prior Year	(224)	(322)

*Excludes the Burger Plant since a decision has been deferred regarding the future of the AQC project or closure of the plant.

Environmental Outlook

With respect to existing environmental laws and regulations, we believe our generation fleet is positioned for compliance due to substantial investment in pollution control equipment we have already made and will continue to make over the next few years pursuant to our AQC plan. The plan includes projects designed to ensure that all of the facilities in our generation fleet are operated in compliance with all applicable emissions standards and limits, including NO_x, SO_2 and mercury. It also fulfills the requirements imposed by the 2005 consent decree that resolved the Sammis NSR litigation. By 2010, we expect approximately 51% of our coal-fired generating fleet to have full NO_x and SO_2 equipment controls and to have significantly decreased our exposure to the volatile emission allowance market for NO_x and SO_2.

In December 2008 we filed a motion with the U.S. District Court for the Southern District of Ohio requesting an extension of the December 31, 2008 deadline in which to decide whether to install scrubbers and other environmental equipment for two 156 MW coal fired units at the R.E. Burger Plant, repower the units by switching from coal to natural gas, or to shut them down in the next two years. On January 30, 2009, the Court approved an extension until March 31, 2009.

The following table shows the percentage of our 2009 generating capacity made up of non-emitting and low-emitting generating units, including coal units retrofitted with best available control technology as well as projections for 2010.

	2009		2010	
Fleet Emission Control Status	**Capacity (MW)**	**Fleet %**	**Capacity (MW)**	**Fleet %**
Non-Emitting	4,642	34	4,642	34
Coal Controlled (SO_2 / NO_x - full control)	2,626	19	3,826	28
Natural Gas Peaking	1,183	9	1,183	9
	8,451	62	9,651	71

Momentum continues to build in the United States for some form of regulation of GHG. We believe that our generation fleet is competitively positioned as we move toward a carbon-constrained world with about 34% of our generation output coming from non-emitting nuclear and hydro power.

While we have relatively low carbon intensity (i.e., CO_2 emitted per KWH) due primarily to our non-emitting nuclear fleet, our total CO_2 emissions will increase as fossil plant utilization increases. We are involved in the following research and other activities, as part of our GHG compliance strategy:

- Pilot testing of CO_2 capture and sequestration technology;
- Electric Power Research Institute's Coal Fleet for Tomorrow;
- Nuclear uprates and license renewals to increase and maintain FES' non-emitting nuclear units; and
- Participation in the DOE's Midwest Regional Carbon Sequestration Partnership, New Jersey's Clean Energy Program, and the EPA's Sulfur Hexafluoride Reduction Partnership.

In addition, we will remain actively engaged in the federal and state debate over future environmental requirements and legislation, especially those dealing with potential global climate change. Due to the significant uncertainty as to the final form of any such legislation at both the federal and state levels, it is possible that we could be required to make additional capital expenditures, which could adversely impact on our financial condition and results of operations.

Achieving Our Vision

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

RISKS AND CHALLENGES

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

- risks arising from the reliability of our power plants and transmission and distribution equipment;
- changes in commodity prices could adversely affect our profit margins;
- we are exposed to operational, price and credit risks associated with selling and marketing products in the power markets that we do not always completely hedge against;
- the use of derivative contracts by us to mitigate risks could result in financial losses that may negatively impact our financial results;
- our risk management policies relating to energy and fuel prices, and counterparty credit are by their very nature risk related, and we could suffer economic losses despite such policies;
- nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- capital market performance and other changes may decrease the value of decommissioning trust fund, pension fund assets and other trust funds which then could require significant additional funding;
- we could be subject to higher costs and/or penalties related to mandatory NERC/FERC reliability standards;
- we rely on transmission and distribution assets that we do not own or control to deliver our wholesale electricity. If transmission is disrupted including our own transmission, or not operated efficiently, or if capacity is inadequate, our ability to sell and deliver power may be hindered;
- disruptions in our fuel supplies could occur, which could adversely affect our ability to operate our generation facilities and impact financial results;
- temperature variations as well as weather conditions or other natural disasters could have a negative impact on our results of operations and demand significantly below or above our forecasts could adversely affect our energy margins;
- we are subject to financial performance risks related to general economic cycles and also related to heavy manufacturing industries such as automotive and steel;
- increases in customer electric rates and the impact of the economic downturn may lead to a greater amount of uncollectible customer accounts;
- the goodwill of one or more of our operating subsidiaries may become impaired, which would result in write-offs of the impaired amounts;
- we face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- significant increases in our operation and maintenance expenses, including our health care and pension costs, could adversely affect our future earnings and liquidity;
- our business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to our reputation and/or results of operations;
- acts of war or terrorism could negatively impact our business;
- capital improvements and construction projects may not be completed within forecasted budget, schedule or scope parameters;
- changes in technology may significantly affect our generation business by making our generating facilities less competitive;

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

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

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

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

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

- there are uncertainties relating to our participation in RTOs;

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

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

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

- remediation of environmental contamination at current or formerly owned facilities;

- availability and cost of emission credits could materially impact our costs of operations;

- mandatory renewable portfolio requirements could negatively affect our costs;

- we are and may become subject to legal claims arising from the presence of asbestos or other regulated substances at some of our facilities;

- the continuing availability and operation of generating units is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;

- future changes in financial accounting standards may affect our reported financial results;

- interest rates and/or a credit rating downgrade could negatively affect our financing costs, our ability to access capital and our requirement to post collateral;

- we must rely on cash from our subsidiaries and any restrictions on our utility subsidiaries' ability to pay dividends or make cash payments to us may adversely affect our financial condition;

- we cannot assure common shareholders that future dividend payments will be made, or if made, in what amounts they may be paid;

- disruptions in the capital and credit markets may adversely affect our business, including the availability and cost of short-term funds for liquidity requirements, our ability to meet long-term commitments, our ability to hedge effectively our generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect our results of operations, cash flows and financial condition;

- questions regarding the soundness of financial institutions or counterparties could adversely affect us;

- our electric utility operating affiliates in Ohio are currently in the midst of rate proceedings that have the potential to adversely affect our financial condition.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among our business segments. A reconciliation of segment financial results is provided in Note 15 to the consolidated financial statements. Net income by major business segment was as follows:

	2008	2007	2006	Increase (Decrease) 2008 vs 2007	Increase (Decrease) 2007 vs 2006
	(In millions, except per share amounts)				
Net Income					
By Business Segment:					
Energy delivery services	$ 833	$ 862	$ 893	$ (29)	$ (31)
Competitive energy services	472	495	393	(23)	102
Ohio transitional generation services	83	103	112	(20)	(9)
Other and reconciling adjustments*	(46)	(151)	(144)	105	(7)
Total	$ 1,342	$ 1,309	$ 1,254	$ 33	$ 55
Basic Earnings Per Share:					
Income from continuing operations	$ 4.41	$ 4.27	$ 3.85	$ 0.14	$ 0.42
Discontinued operations	-	-	(0.01)	-	0.01
Basic earnings per share	$ 4.41	$ 4.27	$ 3.84	$ 0.14	$ 0.43
Diluted Earnings Per Share:					
Income from continuing operations	$ 4.38	$ 4.22	$ 3.82	$ 0.16	$ 0.40
Discontinued operations	-	-	(0.01)	-	0.01
Diluted earnings per share	$ 4.38	$ 4.22	$ 3.81	$ 0.16	$ 0.41

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

Summary of Results of Operations – 2008 Compared with 2007

Financial results for our major business segments in 2008 and 2007 were as follows:

2008 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,540	$ 1,333	$ 2,820	$ -	$ 12,693
Other	626	238	82	(12)	934
Internal	-	2,968	-	(2,968)	-
Total Revenues	9,166	4,539	2,902	(2,980)	13,627
Expenses:					
Fuel	2	1,338	-	-	1,340
Purchased power	4,161	779	2,319	(2,968)	4,291
Other operating expenses	1,648	1,142	374	(122)	3,042
Provision for depreciation	417	243	-	17	677
Amortization of regulatory assets	1,002	-	51	-	1,053
Deferral of new regulatory assets	(329)	-	13	-	(316)
General taxes	640	109	6	23	778
Total Expenses	7,541	3,611	2,763	(3,050)	10,865
Operating Income	1,625	928	139	70	2,762
Other Income (Expense):					
Investment income (loss)	170	(34)	1	(78)	59
Interest expense	(410)	(152)	(1)	(191)	(754)
Capitalized interest	3	44	-	5	52
Total Other Expense	(237)	(142)	-	(264)	(643)
Income Before Income Taxes	1,388	786	139	(194)	2,119
Income taxes	555	314	56	(148)	777
Net Income	$ 833	$ 472	$ 83	$ (46)	$ 1,342

2007 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,069	$ 1,316	$ 2,559	$ -	$ 11,944
Other	657	152	37	12	858
Internal	-	2,901	-	(2,901)	-
Total Revenues	8,726	4,369	2,596	(2,889)	12,802
Expenses:					
Fuel	5	1,173	-	-	1,178
Purchased power	3,733	764	2,240	(2,901)	3,836
Other operating expenses	1,700	1,160	305	(79)	3,086
Provision for depreciation	404	204	-	30	638
Amortization of regulatory assets	991	-	28	-	1,019
Deferral of new regulatory assets	(371)	-	(153)	-	(524)
General taxes	623	107	4	20	754
Total Expenses	7,085	3,408	2,424	(2,930)	9,987
Operating Income	1,641	961	172	41	2,815
Other Income (Expense):					
Investment income	240	16	1	(137)	120
Interest expense	(456)	(172)	(1)	(146)	(775)
Capitalized interest	11	20	-	1	32
Total Other Expense	(205)	(136)	-	(282)	(623)
Income Before Income Taxes	1,436	825	172	(241)	2,192
Income taxes	574	330	69	(90)	883
Net Income	$ 862	$ 495	$ 103	$ (151)	$ 1,309
Changes Between 2008 and 2007 Financial Results - Increase (Decrease)					
Revenues:					
External					
Electric	$ 471	$ 17	$ 261	$ -	$ 749
Other	(31)	86	45	(24)	76
Internal	-	67	-	(67)	-
Total Revenues	440	170	306	(91)	825
Expenses:					
Fuel	(3)	165	-	-	162
Purchased power	428	15	79	(67)	455
Other operating expenses	(52)	(18)	69	(43)	(44)
Provision for depreciation	13	39	-	(13)	39
Amortization of regulatory assets	11	-	23	-	34
Deferral of new regulatory assets	42	-	166	-	208
General taxes	17	2	2	3	24
Total Expenses	456	203	339	(120)	878
Operating Income	(16)	(33)	(33)	29	(53)
Other Income (Expense):					
Investment income (loss)	(70)	(50)	-	59	(61)
Interest expense	46	20	-	(45)	21
Capitalized interest	(8)	24	-	4	20
Total Other Income (Expense)	(32)	(6)	-	18	(20)
Income Before Income Taxes	(48)	(39)	(33)	47	(73)
Income taxes	(19)	(16)	(13)	(58)	(106)
Net Income	$ (29)	$ (23)	$ (20)	$ 105	$ 33

Energy Delivery Services – 2008 Compared to 2007

Net income decreased $29 million to $833 million in 2008 compared to $862 million in 2007, primarily due to increased purchased power costs and lower investment income, partially offset by higher revenues.

Revenues –

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	2008	2007	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,882	$ 3,909	$ (27)
Generation sales:			
Retail	3,315	3,145	170
Wholesale	951	687	264
Total generation sales	4,266	3,832	434
Transmission	836	785	51
Other	182	200	(18)
Total Revenues	$ 9,166	$ 8,726	$ 440

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

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

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

The following table summarizes the price and volume factors contributing to the $434 million increase in generation revenues in 2008 compared to 2007:

Sources of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 2.2% decrease in sales volumes	$ (69)
Change in prices	239
	170
Wholesale:	
Effect of 1.2% decrease in sales volumes	(8)
Change in prices	272
	264
Net Increase in Generation Revenues	$ 434

The decrease in retail generation sales volumes reflected an increase in customer shopping in the service territories of Penn, Penelec, and JCP&L and the weather-related impacts described above. The increase in retail generation prices in 2008 was due to higher generation rates for JCP&L resulting from the New Jersey BGS auctions effective June 1, 2007 and June 1, 2008. Wholesale generation sales decreased principally as a result of JCP&L selling less power into the PJM market, reflecting decreased purchased power volumes from NUGs. The increase in wholesale prices reflected higher spot market prices for PJM market participants.

Transmission revenues increased $51 million primarily due to higher transmission rates for Met-Ed and Penelec resulting from the annual update to their TSC riders in mid-2008. Met-Ed and Penelec defer the difference between revenues from their transmission rider and transmission costs incurred with no material effect on current period earnings (see Regulatory Matters – Pennsylvania).

Expenses –

The net revenue increase discussed above was more than offset by a $456 million increase in expenses due to the following:

- Purchased power costs were $428 million higher in 2008 due to higher unit costs and a decrease in the amount of NUG costs deferred. The increased unit costs primarily reflected the effect of higher JCP&L costs resulting from the BGS auction process. JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. The following table summarizes the sources of changes in purchased power costs:

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	(113)
	343
Purchases from FES:	
Change due to decreased unit costs	(18)
Change due to decreased volumes	(10)
	(28)
Decrease in NUG costs deferred	113
Net Increase in Purchased Power Costs	$ 428

- Other operating expenses decreased $52 million due primarily to:
  - a $15 million decrease for contractor costs associated with vegetation management activities, as more of that work performed in 2008 related to capital projects;
  - a $13 million decrease in uncollectible expense due primarily to the recognition of higher uncollectible reserves in 2007 and enhanced collection processes in 2008;
  - lower labor costs charged to operating expense of $12 million, as a greater proportion of labor was devoted to capital-related projects in 2008; and
  - a $6 million decline in regulatory program costs, including customer rebates.
- Amortization of regulatory assets increased $11 million due to higher transition cost amortization for the Ohio Companies, partially offset by decreases at JCP&L for regulatory assets that were fully recovered at the end of 2007 and in the first half of 2008.
- The deferral of new regulatory assets during 2008 was $42 million lower primarily due to the absence of the one-time deferral in 2007 of decommissioning costs related to the Saxton nuclear research facility ($27 million) and lower PJM transmission cost deferrals ($32 million) offset by increased societal benefit deferrals ($15 million).
- Higher depreciation expense of $13 million resulted from additional capital projects placed in service since 2007.
- General taxes increased $17 million due to higher gross receipts taxes, property taxes and payroll taxes.

Other Expense –

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

Competitive Energy Services – 2008 Compared to 2007

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

Revenues –

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

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

Revenues by Type of Service	2008	2007	Increase (Decrease)
		(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.

Ohio Transitional Generation Services – 2008 Compared to 2007

Net income for this segment decreased to $83 million in 2008 from $103 million in 2007. Higher operating expenses and a decrease in the deferral of new regulatory assets were partially offset by higher generation revenues.

Revenues –

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

Revenues by Type of Service	**2008**	**2007**	**Increase (Decrease)**
		(In millions)	
Generation sales:			
Retail	$ 2,453	$ 2,248	$ 205
Wholesale	11	7	4
Total generation sales	2,464	2,255	209
Transmission	431	333	98
Other	7	8	(1)
Total Revenues	$ 2,902	$ 2,596	$ 306

The following table summarizes the price and volume factors contributing to the net increase in sales revenues from retail customers:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 1.6% decrease in sales volumes	$ (37)
Change in prices	242
Net Increase in Retail Generation Revenues	$ 205

The decrease in generation sales volume in 2008 was primarily due to milder weather and economic conditions. Cooling degree days in OE's, CEI's and TE's service territories for 2008 decreased by 27.7%, 13.6% and 20.3%, respectively, while heating degree days increased on average 5.5% from the previous year. In the industrial sector, a decrease in generation sales to automotive customers (18%) and steel customers (5%) was partially offset by an increase in usage by refining customers (3%). Average prices increased primarily due to an increase in the Ohio Companies' fuel cost recovery riders that became effective in January 2008.

Increased transmission revenue resulted from PUCO-approved transmission tariff increases that became effective July 1, 2007 and July 1, 2008. The difference between transmission revenues accrued and transmission expenses incurred is deferred, resulting in no material impact to current period earnings.

Expenses –

Purchased power costs were $79 million higher due to higher unit costs for power purchased from FES. The factors contributing to the net increase are summarized in the following table:

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to unit costs	$ -
Change due to decreased volumes	(15)
	(15)
Purchases from FES:	
Change due to increased unit costs	128
Change due to decreased volumes	(34)
	94
Net Increase in Purchased Power Costs	$ 79

The higher unit costs reflect the increases in the Ohio Companies' retail generation rates, as provided for under the PSA with FES. The decrease in purchase volumes from FES was due to the lower retail generation sales requirements described above.

Other operating expenses increased $69 million due primarily to reduced intersegment credits associated with the Ohio Companies' nuclear generation leasehold interests and increased MISO transmission-related expenses.

The deferral of new regulatory assets decreased by $166 million and the amortization of regulatory assets increased $23 million in 2008 as compared to 2007. MISO transmission deferrals and RCP fuel deferrals decreased as more transmission and generation costs were recovered from customers through PUCO-approved riders.

Other – 2008 Compared to 2007

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

Summary of Results of Operations – 2007 Compared with 2006

Financial results for our major business segments in 2006 were as follows:

2006 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services (In millions)	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:					
External					
Electric	$ 7,039	$ 1,266	$ 2,366	$ -	$ 10,671
Other	584	163	24	59	830
Internal	14	2,609	-	(2,623)	-
Total Revenues	7,637	4,038	2,390	(2,564)	11,501
Expenses:					
Fuel and purchased power	3,015	1,812	2,050	(2,624)	4,253
Other operating expenses	1,585	1,138	247	(5)	2,965
Provision for depreciation	379	190	-	27	596
Amortization of regulatory assets	841	-	20	-	861
Deferral of new regulatory assets	(375)	-	(125)	-	(500)
General taxes	599	90	10	21	720
Total Expenses	6,044	3,230	2,202	(2,581)	8,895
Operating Income	1,593	808	188	17	2,606
Other Income (Expense):					
Investment income	328	35	-	(214)	149
Interest expense	(431)	(200)	(1)	(89)	(721)
Capitalized interest	14	12	-	-	26
Subsidiaries' preferred stock dividends	(16)	-	-	9	(7)
Total Other Expense	(105)	(153)	(1)	(294)	(553)
Income From Continuing Operations Before Income Taxes	1,488	655	187	(277)	2,053
Income taxes	595	262	75	(137)	795
Income from continuing operations	893	393	112	(140)	1,258
Discontinued operations	-	-	-	(4)	(4)
Net Income	$ 893	$ 393	$ 112	$ (144)	$ 1,254
Changes Between 2007 and 2006 Financial Results - Increase (Decrease)					
Revenues:					
External					
Electric	$ 1,030	$ 50	$ 193	$ -	$ 1,273
Other	73	(11)	13	(47)	28
Internal	(14)	292	-	(278)	-
Total Revenues	1,089	331	206	(325)	1,301
Expenses:					
Fuel and purchased power	723	125	190	(277)	761
Other operating expenses	115	22	58	(74)	121
Provision for depreciation	25	14	-	3	42
Amortization of regulatory assets	150	-	8	-	158
Deferral of new regulatory assets	4	-	(28)	-	(24)
General taxes	24	17	(6)	(1)	34
Total Expenses	1,041	178	222	(349)	1,092
Operating Income	48	153	(16)	24	209
Other Income (Expense):					
Investment income	(88)	(19)	1	77	(29)
Interest expense	(25)	28	-	(57)	(54)
Capitalized interest	(3)	8	-	1	6
Subsidiaries' preferred stock dividends	16	-	-	(9)	7
Total Other Income (Expense)	(100)	17	1	12	(70)
Income From Continuing Operations Before Income Taxes	(52)	170	(15)	36	139
Income taxes	(21)	68	(6)	47	88
Income from continuing operations	(31)	102	(9)	(11)	51
Discontinued operations	-	-	-	4	4
Net Income	$ (31)	$ 102	$ (9)	$ (7)	$ 55

Energy Delivery Services – 2007 Compared to 2006

Net income decreased $31 million to $862 million in 2007 compared to $893 million in 2006, primarily due to higher expenses, partially offset by increased revenues.

Revenues –

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	2007	2006	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,909	$ 3,849	$ 60
Generation sales:			
Retail	3,145	2,774	371
Wholesale	687	247	440
Total generation sales	3,832	3,021	811
Transmission	785	561	224
Other	200	206	(6)
Total Revenues	$ 8,726	$ 7,637	$ 1,089

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

Electric Distribution KWH Deliveries	
Residential	4.3 %
Commercial	3.7 %
Industrial	(0.2)%
Net Increase in Distribution KWH Deliveries	2.6 %

The increase in electric distribution deliveries to customers was primarily due to higher weather-related usage during 2007 compared to 2006 (heating degree days increased by 11.2% and cooling degree days increased by 16.7%). The higher revenues from increased distribution deliveries were partially offset by distribution rate decreases of $86 million and $21 million for Met-Ed and Penelec, respectively, as a result of a January 11, 2007 PPUC rate decision (see Regulatory Matters – Pennsylvania).

The following table summarizes the price and volume factors contributing to the $811 million increase in generation sales revenues in 2007 compared to 2006:

Sources of Change in Generation Sales Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 1.7% decrease in sales volumes	$ (48)
Change in prices	419
	371
Wholesale:	
Effect of 120% increase in sales volumes	297
Change in prices	143
	440
Net Increase in Generation Sales Revenues	$ 811

The decrease in retail generation sales volume was primarily due to an increase in customer shopping in Penn's service territory in 2007. The increase in retail generation prices during 2007 compared to 2006 was primarily due to increased generation rates for JCP&L resulting from the New Jersey BGS auction process and an increase in NUGC rates authorized by the NJBPU. Wholesale generation sales increased principally as a result of Met-Ed and Penelec selling additional available power into the PJM market in 2007.

Transmission revenues increased $224 million primarily due to higher transmission rates for Met-Ed and Penelec resulting from the January 2007 PPUC authorization for transmission cost recovery. Met-Ed and Penelec defer the difference between revenues received under their transmission rider and transmission costs incurred, with no material effect on current period earnings (see Regulatory Matters – Pennsylvania).

Expenses –

The increases in revenues discussed above were offset by an approximate $1.0 billion increase in expenses due to the following:

- Purchased power costs were $723 million higher in 2007 due to increases in both unit costs and volumes purchased. The increased unit costs reflected the effect of higher JCP&L costs resulting from the BGS auction process. The increased volumes purchased in 2007 resulted primarily from Met-Ed's and Penelec's higher sales to the PJM wholesale market. The following table summarizes the sources of changes in purchased power costs:

Sources of Change in Purchased Power	**Increase**
	(In millions)
Purchased Power:	
Change due to increased unit costs	$ 349
Change due to increased volume	248
Decrease in NUG costs deferred	126
Net Increase in Purchased Power Costs	$ 723

- Other operating expenses increased $115 million primarily due to the net effects of:

  - an increase of $101 million in MISO and PJM transmission expenses, resulting primarily from higher congestion costs; and

  - an increase in operation and maintenance expenses of $19 million primarily due to increased labor, contractor costs and materials devoted to maintenance projects in 2007.

- Amortization of regulatory assets increased $150 million compared to 2006 due primarily to recovery of deferred BGS costs through higher NUGC rates for JCP&L (as discussed above), recovery of deferred non-NUG stranded costs through application of CTC revenues for Met-Ed and higher transition cost amortization for the Ohio Companies.

- The deferral of new regulatory assets during 2007 was $4 million less in 2007 than in 2006 primarily due to $46 million of lower PJM transmission cost deferrals, partially offset by the deferral of previously expensed decommissioning costs of $27 million related to the Saxton nuclear research facility (see "Regulatory Matters – Pennsylvania") and increased carrying charges earned on the Ohio Companies' RCP distribution deferrals of $11 million.

- Depreciation expense increased $25 million and general taxes increased $24 million due primarily to property additions since 2006.

- Other expenses increased $100 million in 2007 compared to 2006 primarily due to lower investment income of $88 million resulting from the repayment of notes receivable from affiliates since 2006, and increased interest expense of $25 million related to new debt issuances by CEI, JCP&L and Penelec. These increased costs were partially offset by the absence of $16 million of preferred stock dividends paid in 2006.

Competitive Energy Services – 2007 Compared to 2006

Net income for this segment increased $102 million to $495 million in 2007 compared to $393 million in 2006. This increase reflected an improvement in generation margin (revenues less fuel and purchased power), partially offset by higher operating expenses, depreciation and general taxes.

Revenues –

Total revenues increased $331 million in 2007 compared to 2006 primarily as a result of higher unit prices for affiliated generation sales to the Ohio Companies and increased retail sales revenues, partially offset by lower non-affiliated wholesale sales revenues.

The higher retail revenues resulted from increased sales in both the MISO and PJM markets. The increase in MISO retail sales primarily reflects FES' increased sales to shopping customers in Penn's service territory. Lower non-affiliated wholesale revenues reflected the effect of decreased generation available for the non-affiliated wholesale market due to increased affiliated company power sales under the Ohio Companies' full-requirements PSA and the partial-requirements PSA with Met-Ed and Penelec.

The increased affiliated company generation revenues reflected both higher unit prices and increased sales volumes. The increase in PSA sales to the Ohio Companies was due to their higher retail generation sales requirements. Unit prices were higher because rates charged under FES' full-requirements PSAs reflect the increases in the Ohio Companies' composite retail generation rates. The higher sales to the Pennsylvania Companies were due to increased Met-Ed and Penelec generation sales requirements. These increases were partially offset by lower sales to Penn due to the implementation of its competitive solicitation process in 2007.

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

Revenues by Type of Service	2007	2006	Increase (Decrease)
		(In millions)	
Non-Affiliated Generation Sales:			
Retail	$ 712	$ 590	$ 122
Wholesale	603	676	(73)
Total Non-Affiliated Generation Sales	1,315	1,266	49
Affiliated Generation Sales	2,901	2,609	292
Transmission	103	120	(17)
Other	50	43	7
Total Revenues	$ 4,369	$ 4,038	$ 331

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

Source of Change in Non-Affiliated Generation Sales	Increase (Decrease)
	(In millions)
Retail:	
Effect of 10.8% increase in sales volumes	$ 63
Change in prices	59
	122
Wholesale:	
Effect of 22.7% decrease in sales volumes	(154)
Change in prices	81
	(73)
Net Increase in Non-Affiliated Generation Sales	$ 49

Source of Change in Affiliated Generation Sales	Increase
	(In millions)
Ohio Companies:	
Effect of 3.4% increase in sales volumes	$ 68
Change in prices	118
	186
Pennsylvania Companies:	
Effect of 14.9% increase in sales volumes	87
Change in prices	19
	106
Increase in Affiliated Generation Sales	$ 292

Transmission revenues decreased $17 million due in part to reduced FTR revenue resulting from fewer FTRs allocated by MISO ($15 million) and PJM ($9 million), partially offset by higher retail transmission revenues of $8 million.

Expenses –

Total expenses increased $178 million in 2007 compared to 2006 due to the following factors:

- Purchased power costs increased $159 million due principally to higher volumes for replacement power related to the forced outages at the Bruce Mansfield and Perry Plants and costs associated with the new capacity market in PJM ($25 million).

- Fossil generation operating costs were $66 million higher due to the absence of gains from the sale of emissions allowances recognized in 2006 ($27 million) and increased costs related to scheduled and forced maintenance outages during 2007.

- Lease expenses increased $55 million primarily due to intercompany billings associated with the assignment of CEI's and TE's leasehold interests in the Bruce Mansfield Plant to FGCO and the Bruce Mansfield Unit 1 sale and leaseback transaction completed in 2007.

- Depreciation expenses were $14 million higher due to property additions since 2006.

- General taxes were $17 million higher as a result of increased gross receipts taxes and property taxes.

Partially offsetting the higher costs were:

- Fuel costs were $34 million lower primarily due to reduced coal costs and emission allowance costs, offset by increases in nuclear fuel and natural gas costs. Coal costs were reduced due to $38 million of reduced coal consumption reflecting lower generation. Reduced emission allowance costs ($19 million) were partially offset by increased natural gas costs ($7 million) due to increased consumption and nuclear fuel costs ($15 million) due to increased consumption and higher prices.

- Nuclear generation operating costs were $72 million lower due to fewer outages in 2007 compared to 2006 and reduced employee benefit costs.

- MISO transmission expense decreased by $32 million from 2006 due primarily to a one-time resettlement of costs from generation providers to load serving entities.

- Total other expense in 2007 was $17 million lower than in 2006 primarily due to lower interest expense, partially offset by decreased earnings on nuclear decommissioning trust investments.

Ohio Transitional Generation Services – 2007 Compared to 2006

Net income for this segment decreased to $103 million in 2007 from $112 million in 2006. Higher operating expenses, primarily for purchased power, were partially offset by higher generation revenues.

Revenues –

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

Revenues by Type of Service	2007	2006	Increase (Decrease)
		(In millions)	
Generation sales:			
Retail	$ 2,248	$ 2,095	$ 153
Wholesale	7	13	(6)
Total generation sales	2,255	2,108	147
Transmission	333	280	53
Other	8	2	6
Total Revenues	$ 2,596	$ 2,390	$ 206

The following table summarizes the price and volume factors contributing to the increase in sales revenues from retail customers:

Source of Change in Generation Sales Revenues	Increase
	(In millions)
Retail:	
Effect of 3.9% increase in sales volumes	$ 82
Change in prices	71
Total Increase in Retail Generation Sales Revenues	$ 153

The increase in generation sales was primarily due to higher weather-related usage in 2007 compared to 2006 and reduced customer shopping in Ohio. The percentage of generation services provided by alternative suppliers to total sales delivered by the Ohio Companies in their service areas decreased by 5.9 percentage points from 2006. Average prices increased primarily due to higher composite unit prices for returning customers.

Increased transmission revenues resulted from higher sales volumes and a PUCO-approved transmission tariff increase, which became effective July 1, 2007.

Expenses –

Purchased power costs were $190 million higher due primarily to higher unit costs for power purchased from FES. The factors contributing to the higher costs are summarized in the following table:

Source of Change in Purchased Power	Increase
	(In millions)
Purchases from non-affiliates:	
Change due to unit costs	$ -
Change due to volume purchased	4
	4
Purchases from FES:	
Change due to increased unit costs	114
Change due to volume purchased	72
	186
Total Increase in Purchased Power Costs	$ 190

The increase in volumes purchased was due to the higher retail generation sales requirements. The higher unit costs reflect the increases in the Ohio Companies' composite retail generation rates, as provided for under the PSA with FES.

Other operating expenses increased $58 million primarily due to MISO transmission-related expenses. The difference between transmission revenues accrued and transmission expenses incurred is deferred, resulting in no material impact to current period earnings.

Other – 2007 Compared to 2006

Our financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $7 million decrease in our net income in 2007 compared to 2006. The decrease includes the net effect of the sale of our interest in First Communications ($13 million, net of taxes), the absence of subsidiaries' preferred stock dividends in 2007 ($9 million) and the absence of a $4 million loss included in 2006 results from discontinued operations.

DISCONTINUED OPERATIONS

Discontinued operations for 2006 included certain FSG subsidiaries and a portion of MYR. We sold 60% of MYR in March 2006 and began accounting for our remaining interest in MYR under the equity method of accounting for investments. Our remaining interest in MYR was sold in November 2006. MYR's results prior to the sale of the initial 60% in March 2006 and the gain on the March sale are included in discontinued operations. The 2006 MYR results subsequent to the March 2006 sale (recorded as equity investment income) and the gain on the November sale are included in income from continuing operations.

The following table summarizes the sources of income from discontinued operations:

Discontinued Operations (Net of tax)	2006
	(In millions)
Gain on sale – FSG subsidiaries	$ 2
Reclassification of operating (loss) income to discontinued operations:	
FSG subsidiaries	(8)
MYR	2
Loss from discontinued operations	$ (4)

POSTRETIREMENT BENEFITS

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

Postretirement Benefits Costs (Credits)	2008	2007	2006
		(In millions)	
Pension	$ (23)	$ 7	$ 45
OPEB	(37)	(41)	48
Total	$ (60)	$ (34)	$ 93

Reductions in plan assets from investment losses during 2008 resulted in a decrease to the plans' funded status of $1.7 billion and an after-tax decrease in common stockholders' equity of $1.2 billion. As of December 31, 2008, our pension plan was underfunded and we currently anticipate that additional cash contributions will be required in 2011 for the 2010 plan year. The overall actual investment result during 2008 was a loss of 23.8% compared to an assumed 9% positive return. Based on a 7% discount rate, 2009 pre-tax net periodic pension and OPEB expense will be approximately $170 million.

SUPPLY PLAN

Regulated Commodity Sourcing

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

Unregulated Commodity Sourcing

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

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

CAPITAL RESOURCES AND LIQUIDITY

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

We, along with certain of our subsidiaries, have access to $2.75 billion of short-term financing under a revolving credit facility that expires in August 2012. A total of 25 banks participate in the facility, with no one bank having more than 7.3% of the total commitments. As of January 31, 2009, we had $720 million of bank credit facilities in addition to the $2.75 billion revolving credit facility. On October 8, 2008, we obtained a $300 million secured term loan facility with Credit Suisse to reinforce our liquidity in light of the unprecedented disruptions in the credit markets (this facility remains undrawn). In addition, an aggregate of $550 million of accounts receivable financing facilities through the Ohio and Pennsylvania Companies may be accessed to meet working capital requirements and for other general corporate purposes. Our available liquidity as of January 31, 2009, is described in the following table.

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

(1) FirstEnergy Corp. and subsidiary borrowers.
(2) $100 million matures November 30, 2009; $20 million uncommitted line of credit with no maturity date.
(3) Drawn amounts are payable within 30 days and may not be re-borrowed.
(4) $370 million expires February 22, 2010; $180 million expires December 18, 2009.

In early October 2008, we negotiated with the banks that have issued irrevocable direct pay LOCs in support of our outstanding variable interest rate PCRBs ($2.1 billion as of December 31, 2008) to extend the respective reimbursement obligations of our applicable subsidiary obligors in the event that such LOCs are drawn upon. As discussed below, the LOCs supporting these PCRBs may be drawn upon to pay the purchase price to bondholders that have exercised the right to tender their PCRBs for mandatory purchase. Approximately $972 million of LOCs that previously required reimbursement within 30 days or less of a draw under the applicable LOC have now been modified to extend the reimbursement obligations to six months or June 2009, as applicable. Subject to market conditions, we expect to address our LOC expirations in 2009 by either renewing or replacing the majority of the LOCs. In addition, approximately $250 million of our PCRBs that are currently supported by LOCs are expected to be remarketed or refinanced in fixed interest rate modes, thereby eliminating the need for credit support. The LOCs for our variable interest rate PCRBs were issued by seven banks, as summarized in the following table:

LOC Bank	Aggregate LOC Amount[5] (In millions)	LOC Termination Date	Reimbursements of LOC Draws Due
Barclays Bank[1]	$ 149	June 2009	June 2009
Bank of America[1][2]	101	June 2009	June 2009
The Bank of Nova Scotia[1]	255	Beginning June 2010	Shorter of 6 months or LOC termination date
The Royal Bank of Scotland[1]	131	June 2012	6 months
KeyBank[1][3]	266	June 2010	6 months
Wachovia Bank[6]	591	March 2009	March 2009
Barclays Bank[4]	528	Beginning December 2010	30 days
PNC Bank	70	Beginning December 2010	180 days
Total	$ 2,091		

(1) Due dates for reimbursements of LOC draws for these banks were extended in October 2008 from 30 days or less to the dates indicated.
(2) Supported by 2 participating banks, with each having 50% of the total commitment.
(3) Supported by 4 participating banks, with the LOC bank having 62% of the total commitment.
(4) Supported by 18 participating banks, with no one bank having more than 14% of the total commitment.
(5) Includes approximately $21 million of applicable interest coverage.
(6) On February 12, 2009, $153 million was renewed, with termination in March 2014.

In February 2009, holders of approximately $434 million in principal of LOC-supported PCRBs of NGC were notified that the applicable Wachovia Bank LOCs expire on March 18, 2009. As a result, these PCRBs are subject to mandatory purchase at a price equal to the principal amount, plus accrued and unpaid interest, which FES and NGC expect to fund through short-term borrowings. Subject to market conditions, FES and NGC expect to remarket or refinance these PCRBs during the remainder of 2009.

As of December 31, 2008, our net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings ($2.4 billion) and the classification of certain variable interest rate PCRBs as currently payable long-term debt. Currently payable long-term debt as of December 31, 2008 included the following:

Currently Payable Long-term Debt		
		(In millions)
PCRBs supported by bank LOCs[1]	$	2,070
FGCO & NGC unsecured PCRBs[1]		82
Penelec unsecured notes[2]		100
CEI secured notes[3]		150
NGC collateralized lease obligation bonds		36
Sinking fund requirements		38
	$	2,476

[1] Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.
[2] Mature in April 2009.
[3] Mature in November 2009.

Changes in Cash Position

During 2008, we received $995 million of cash dividends from our subsidiaries and paid $671 million in cash dividends to common shareholders. With the exception of Met-Ed, which is currently in an accumulated deficit position, there are no material restrictions on the payment of cash dividends by our subsidiaries. In addition to paying dividends from retained earnings, each of our electric utility subsidiaries has authorization from the FERC to pay cash dividends from paid-in capital accounts, as long as its debt to total capitalization ratio (without consideration of retained earnings) remains below 65%.

As of December 31, 2008, we had $545 million in cash and cash equivalents compared to $129 million as of December 31, 2007. Cash and cash equivalents consist of unrestricted, highly liquid instruments with an original or remaining maturity of three months or less. As of December 31, 2008, approximately $472 million of cash and cash equivalents represented temporary overnight deposits. The major sources of changes in these balances are summarized below.

Cash Flows from Operating Activities

Our consolidated net cash from operating activities is provided primarily by our energy delivery services and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $2.2 billion in 2008, $1.7 billion in 2007 and $1.9 billion in 2006, as summarized in the following table:

		2008		2007		2006
				(In millions)		
Net income	$	1,342	$	1,309	$	1,254
Non-cash charges		1,405		670		783
Pension trust contribution*		-		(300)		90
Working capital and other		(528)		15		(188)
	$	2,219	$	1,694	$	1,939

* The $90 million cash inflow in 2006 represents reduced income taxes paid in 2006 relating to the $300 million pension trust contribution made in January 2007.

Net cash provided from operating activities increased by $525 million in 2008 primarily due to the absence of a $300 million pension trust contribution in 2007, a $735 million increase in non-cash charges, and a $33 million increase in net income (see Results of Operations above), partially offset by a $543 million decrease from working capital and other changes.

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

Net cash provided from operating activities decreased by $245 million in 2007, compared to 2006, primarily due to the $300 million pension trust contribution in 2007 and a $113 million change in non-cash charges, partially offset by a $203 million change in working capital and other and a $55 million increase in net income (see Results of Operations above). The changes in working capital and other primarily resulted from changes in accrued taxes of $246 million and materials and supplies of $104 million, due to lower coal inventory levels, partially offset by changes in receivables of $241 million due to higher sales and changes in accounts payable of $48 million.

Cash Flows from Financing Activities

In 2008, net cash provided from financing activities was $1.2 billion compared to net cash used of $1.3 billion in 2007 and $804 million in 2006. The change in 2008 was primarily due to higher short-term borrowings primarily for capital expenditures for environmental compliance and to fund strategic acquisitions, including the Fremont Plant ($275 million), Signal Peak ($125 million), and the purchase of lessor equity interests in Beaver Valley Unit 2 and Perry ($438 million). The absence of the repurchases of common stock in 2007 and 2006 also contributed to the increase in the 2008 period. The following table summarizes security issuances and redemptions or repurchases during the three years ended December 31, 2008.

Securities Issued or Redeemed / Repurchased	**2008**	**2007**	**2006**
		(In millions)	
New issues			
First mortgage bonds	$ 592	$ -	$ -
Pollution control notes	692	427	1,157
Senior secured notes	-	-	382
Unsecured notes	83	1,093	1,192
	$ 1,367	$ 1,520	$ 2,731
Redemptions / Repurchases			
First mortgage bonds	$ 126	$ 293	$ 41
Pollution control notes	698	436	1,189
Senior secured notes	35	188	182
Unsecured notes	175	153	1,100
Common stock	-	969	600
Preferred stock	-	-	193
	$ 1,034	$ 2,039	$ 3,305
Short-term borrowings (repayments), net	$ 1,494	$ (205)	$ 386

We had approximately $2.4 billion of short-term indebtedness as of December 31, 2008 compared to approximately $903 million as of December 31, 2007.

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

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

On October 20, 2008, OE issued and sold $300 million of FMBs, comprised of $275 million 8.25% Series due 2038 and $25 million 8.25% Series due 2018. OE used the net proceeds from this offering to fund capital expenditures and for other general corporate purposes. On November 18, 2008, CEI issued and sold $300 million of 8.875% Series of FMBs due 2018. CEI used the net proceeds from the sale to repay short-term borrowings and for other general corporate purposes. On January 20, 2009, Met-Ed issued and sold $300 million of 7.70% Senior Notes due 2019. Met-Ed used the net proceeds from this offering to repay short-term borrowings. On January 27, 2009, JCP&L issued and sold $300 million of 7.35% Senior Notes due 2019. JCP&L used the net proceeds from the sale to repay short-term borrowings, for capital expenditures, and for other general corporate purposes.

As of December 31, 2008, our currently payable long-term debt includes approximately $2.1 billion (FES - $1.9 billion, OE - $100 million, Met-Ed - $29 million and Penelec - $45 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

Prior to the third quarter of 2008, we had not experienced any unsuccessful remarketings of these variable-rate PCRBs. Coincident with recent disruptions in the variable-rate demand bond and capital markets generally, certain of the PCRBs had been tendered by bondholders to the trustee. All PCRBs that had been tendered were successfully remarketed.

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

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of December 31, 2008:

Borrower	**Revolving Credit Facility Sub-Limit**	**Regulatory and Other Short-Term Debt Limitations**
	(In millions)	
FirstEnergy	$ 2,750	$ -(1)
FES	1,000	-(1)
OE	500	500
Penn	50	39(2)
CEI	250(3)	500
TE	250(3)	500
JCP&L	425	428(2)
Met-Ed	250	300(2)
Penelec	250	300(2)
ATSI	-(4)	50

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

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

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

(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that either (i) ATSI has senior unsecured debt ratings of at least BBB- by S&P and Baa3 by Moody's or (ii) FirstEnergy has guaranteed ATSI's obligations of such borrower under the facility.

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

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of December 31, 2008, our debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy[(1)]	63.0%
FES	56.7%
OE	48.6%
Penn	20.2%
CEI	55.1%
TE	46.1%
JCP&L	32.5%
Met-Ed	44.6%
Penelec	52.8%

(1) As of December 31, 2008, FirstEnergy could issue additional debt of approximately $1.3 billion or recognize a reduction in equity of approximately $700 million, and remain within the limitations of the financial covenants required by its revolving credit facility.

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

Our regulated companies also have the ability to borrow from each other and FirstEnergy to meet their short-term working capital requirements. A similar but separate arrangement exists among our unregulated companies. FESC administers these two money pools and tracks our surplus funds and those of our respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2008 was 2.93% for the regulated companies' money pool and 2.87% for the unregulated companies' money pool.

Our access to capital markets and costs of financing are influenced by the ratings of our securities. The following table displays our securities ratings as of December 31, 2008. On August 1, 2008, S&P changed its outlook for FirstEnergy and our subsidiaries from "negative" to "stable." On November 5, 2008, S&P raised its senior unsecured rating on OE, Penn, CEI and TE to BBB from BBB-. Moody's outlook for FirstEnergy and our subsidiaries remains "stable."

Issuer	Securities	S&P	Moody's
FirstEnergy	Senior unsecured	BBB-	Baa3
FES	Senior unsecured	BBB	Baa2
OE	Senior secured	BBB+	Baa1
	Senior unsecured	BBB	Baa2
Penn	Senior secured	A-	Baa1
CEI	Senior secured	BBB+	Baa2
	Senior unsecured	BBB	Baa3
TE	Senior unsecured	BBB	Baa3
JCP&L	Senior unsecured	BBB	Baa2
Met-Ed	Senior unsecured	BBB	Baa2
Penelec	Senior unsecured	BBB	Baa2

Cash Flows from Investing Activities

Net cash flows used in investing activities resulted principally from property additions. Additions for the energy delivery services segment primarily include expenditures related to transmission and distribution facilities. Capital spending by the competitive energy services segment is principally generation-related. The following table summarizes investing activities for the three years ended December 31, 2008 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
Sources (Uses)		(In millions)		
2008				
Energy delivery services	$ (839)	$ (41)	$ (17)	$ (897)
Competitive energy services	(1,835)	(14)	(56)	(1,905)
Other	(176)	106	(61)	(131)
Inter-Segment reconciling items	(38)	(12)	-	(50)
Total	$ (2,888)	$ 39	$ (134)	$ (2,983)
2007				
Energy delivery services	$ (814)	$ 53	$ (6)	$ (767)
Competitive energy services	(740)	1,300	-	560
Other	(21)	2	(14)	(33)
Inter-Segment reconciling items	(58)	(15)	-	(73)
Total	$ (1,633)	$ 1,340	$ (20)	$ (313)
2006				
Energy delivery services	$ (629)	$ 142	$ (5)	$ (492)
Competitive energy services	(644)	34	(40)	(650)
Other	(4)	102	(18)	80
Inter-Segment reconciling items	(38)	(9)	-	(47)
Total	$ (1,315)	$ 269	$ (63)	$ (1,109)

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

Net cash used for investing activities in 2007 decreased by $796 million compared to 2006. The decrease was principally due to approximately $1.3 billion in cash proceeds from the Bruce Mansfield Unit 1 sale and leaseback transaction. Partially offsetting the cash proceeds from the sale and leaseback transaction was a $318 million increase in property additions which reflects AQC system and distribution system reliability program expenditures and a $49 million decrease in cash provided from cash investments, primarily from the use of restricted cash investments to repay debt during 2006.

Our capital spending for the period 2009-2013 is expected to be approximately $8.1 billion (excluding nuclear fuel), of which approximately $1.6 billion applies to 2009. Investments for additional nuclear fuel during the 2009-2013 period are estimated to be approximately $1.3 billion, of which about $342 million applies to 2009. During the same periods, our nuclear fuel investments are expected to be reduced by approximately $1.0 billion and $137 million, respectively, as the nuclear fuel is consumed.

CONTRACTUAL OBLIGATIONS

As of December 31, 2008, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2009	2010-2011	2012-2013	Thereafter
			(In millions)		
Long-term debt	$ 11,585	$ 323	$ 1,899	$ 667	$ 8,696
Short-term borrowings	2,397	2,397	-	-	-
Interest on long-term debt [1]	8,915	646	1,243	1,026	6,000
Operating leases [2]	3,457	203	349	413	2,492
Fuel and purchased power [3]	21,055	3,294	6,403	4,729	6,629
Capital expenditures	1,120	454	554	101	11
Pension funding	1,123	-	101	463	559
Other [4]	272	8	4	120	140
Total	$ 49,924	$ 7,325	$ 10,553	$ 7,519	$ 24,527

(1) Interest on variable-rate debt based on rates as of December 31, 2008.
(2) See Note 6 to the consolidated financial statements.
(3) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(4) Includes amounts for capital leases (see Note 6) and contingent tax liabilities (see Note 9).

Guarantees and Other Assurances

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

As of December 31, 2008, our maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $4.4 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries	
Energy and Energy-Related Contracts [1]	$ 408
LOC (long-term debt) – interest coverage [2]	6
Other [3]	752
	1,166
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	78
LOC (long-term debt) – interest coverage [2]	10
FES' guarantee of FGCO's sale and leaseback obligations	2,552
	2,640
Surety Bonds	95
LOC (long-term debt) – interest coverage [2]	5
LOC (non-debt) [4][5]	462
	562
Total Guarantees and Other Assurances	$ 4,368

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating-rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $2.1 billion is reflected as debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $300 million for OVEC obligations and $80 million for nuclear decommissioning funding assurances. Also includes $300 million for a Credit Suisse credit facility for FGCO that is guaranteed by both FirstEnergy and FES.

(4) Includes $37 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facility.

(5) Includes approximately $291 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $134 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

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

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade to below investment grade or "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2008, our maximum exposure under these collateral provisions was $585 million as shown below:

Collateral Provisions	FES	Utilities	Total
		(In million)	
Credit rating downgrade to below investment grade	$ 266	$ 259	$ 525
Material adverse event	54	6	60
Total	$ 320	$ 265	$ 585

Stress case conditions of a credit rating downgrade or "material adverse event" and hypothetical adverse price movements in the underlying commodity markets would increase the total potential amount to $689 million, consisting of $61 million due to "material adverse event" contractual clauses and $628 million due to a below investment grade credit rating.

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

In addition to guarantees and surety bonds, FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' power portfolio as of December 31, 2008, and forward prices as of that date, FES had $103 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (15% decrease in prices), FES would be required to post an additional $98 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on our Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, decreased to $1.7 billion as of December 31, 2008, from $2.3 billion as of December 31, 2007, due primarily to NGC's purchase of certain lessor equity interests in Perry Unit 1 and Beaver Valley Unit 2 (see Note 7).

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

MARKET RISK INFORMATION

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

Commodity Price Risk

We are exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices -- electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. Derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of our derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the tables below. Contracts that are not exempt from such treatment include certain power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts are adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs or regulatory liability for below-market costs. The changes in the fair value of commodity derivative contracts related to energy production during 2008 are summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
		(In millions)	
Change in the Fair Value of Commodity Derivative Contracts:			
Outstanding net liability as of January 1, 2008	$ (765)	$ (26)	$ (791)
Additions/change in value of existing contracts	194	(19)	175
Settled contracts	267	4	271
Outstanding net liability as of December 31, 2008[(1)]	$ (304)	$ (41)	$ (345)
Non-commodity Net Liabilities as of December 31, 2008:			
Interest rate swaps[(2)]	-	(3)	(3)
Net Liabilities - Derivative Contracts as of December 31, 2008	**$ (304)**	**$ (44)**	**$ (348)**
Impact of Changes in Commodity Derivative Contracts[(3)]			
Income Statement effects (pre-tax)	$ (1)	$ -	$ (1)
Balance Sheet effects:			
OCI (pre-tax)	$ -	$ (15)	$ (15)
Regulatory asset (net)	$ (462)	$ -	$ (462)

(1) Includes $303 million of non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.
(2) Interest rate swaps are treated as cash flow or fair value hedges.
(3) Represents the change in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives are included on the Consolidated Balance Sheet as of December 31, 2008 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
		(In millions)	
Current-			
Other assets	$ 1	11	$ 12
Other liabilities	(2)	(43)	(45)
Non-Current-			
Other deferred charges	463	-	463
Other noncurrent liabilities	(766)	(12)	(778)
Net liabilities	**$ (304)**	**$ (44)**	**$ (348)**

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, we rely on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. We use these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 5). Sources of information for the valuation of commodity derivative contracts as of December 31, 2008 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2009	2010	2011	2012	2013	Thereafter	Total
				(In millions)			
Prices actively quoted[(1)]	$ (16)	$ (9)	$ -	$ -	$ -	$ -	$ (25)
Other external sources[(2)]	(248)	(200)	(172)	(100)	-	-	(720)
Prices based on models	-	-	-	-	45	355	400
Total[(3)]	$ (264)	$ (209)	$ (172)	$ (100)	$ 45	$ 355	$ (345)

(1) Exchange traded.
(2) Broker quote sheets validated by observable market transactions.
(3) Includes $303 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on our derivative instruments would not have had a material effect on our consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2008. Based on derivative contracts held as of December 31, 2008, an adverse 10% change in commodity prices would decrease net income by approximately $2 million during the next 12 months.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There-after	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 98	$ 85	$ 79	$ 96	$ 118	$ 1,630	$ 2,106	$ 2,105
Average interest rate	5.6%	7.1%	7.8%	7.8%	7.6%	4.8%	5.3%	
Liabilities								
Long-term Debt:								
Fixed rate	$ 323	$ 245	$ 1,592	$ 104	$ 563	$ 6,448	$ 9,275	$ 8,836
Average interest rate	7.0%	6.1%	6.5%	7.9%	5.9%	6.7%	6.6%	
Variable rate		$ 62				$ 2,248	$ 2,310	$ 2,310
Average interest rate		3.4%				1.5%	1.5%	
Short-term Borrowings:	$ 2,397						$ 2,397	$ 2,397
Average interest rate	1.2%						1.2%	

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6 to the consolidated financial statements, our investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Forward Starting Swap Agreements - Cash Flow Hedges

We utilize forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with anticipated future issuances of fixed-rate, long-term debt securities for one or more of our consolidated subsidiaries in 2008 and 2009, and anticipated variable-rate, short-term debt. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury and LIBOR rates between the date of hedge inception and the date of the debt issuance. We consider counterparty credit and nonperformance risk in our hedge assessments and continue to expect the forward-starting swaps to be effective in protecting against the risk of changes in future interest payments. During 2008, we entered into forward swaps with an aggregate notional value of $1.3 billion and terminated forward swaps with an aggregate notional value of $1.4 billion. We paid $49 million in cash related to the terminations, $7 million of which was deemed ineffective and recognized in current period earnings. The remaining effective portion will be recognized over the terms of the associated future debt. As of December 31, 2008, we had outstanding forward swaps with an aggregate notional amount of $300 million and an aggregate fair value of $(3) million.

	December 31, 2008			December 31, 2007		
Forward Starting Swaps	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
			(In millions)			
Cash flow hedges	$ 100	2009	$ (2)	$ -	2009	$ -
	100	2010	(2)	-	2010	-
	-	2015	-	25	2015	(1)
	-	2018	-	325	2018	(1)
	100	2019	1	-	2019	-
	-	2020	-	50	2020	(1)
	$ 300		$ (3)	$ 400		$ (3)

Equity Price Risk

We provide a noncontributory qualified defined benefit pension plan that covers substantially all of our employees and non-qualified pension plans that cover certain employees. The plan provides defined benefits based on years of service and compensation levels. We also provide health care benefits, which include certain employee contributions, deductibles, and co-payments, upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. Our benefit plan assets and obligations are remeasured annually using a December 31 measurement date. Reductions in plan assets from investment losses during 2008 resulted in a decrease to the plans' funded status of $1.7 billion and an after-tax decrease to common stockholders' equity of $1.2 billion. As of December 31, 2008, our pension plan was underfunded and we estimate that additional cash contributions will be required in 2011 for the 2010 plan year. The overall actual investment result during 2008 was a loss of 23.8% compared to an assumed 9% positive return. Based on a 7% discount rate, 2009 pre-tax net periodic pension and OPEB expense will be approximately $170 million.

Nuclear decommissioning trust funds have been established to satisfy NGC's and our Utilities' nuclear decommissioning obligations. As of December 31, 2008, approximately 37% of the funds were invested in equity securities and 63% were invested in fixed income securities, with limitations related to concentration and investment grade ratings. The equity securities are carried at their market value of approximately $627 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $63 million reduction in fair value as of December 31, 2008. The decommissioning trusts of JCP&L and the Pennsylvania Companies are subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NGC, OE and TE recognize in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts based on the guidance for other-than-temporary impairments provided in SFAS 115, FSP SFAS 115-1 and SFAS 124-1. Nuclear decommissioning trust securities impairments totaled $123 million in 2008. We do not expect to make additional cash contributions to the nuclear decommissioning trusts in 2009, other than the required annual TMI-2 trust contribution that is collected through customer rates. However, should the trust funds continue to experience declines in market value, we may be required to take measures, such as providing financial guarantees through LOCs or parental guarantees or making additional contributions to the trusts to ensure that the trusts are adequately funded and meet minimum NRC funding requirements.

CREDIT RISK

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

We maintain credit policies with respect to our counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of our credit program, we aggressively manage the quality of our portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB+ (S&P). As of December 31, 2008, the largest credit concentration was with JP Morgan, which is currently rated investment grade, representing 10.8% of our total approved credit risk.

REGULATORY MATTERS

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities with the opportunity to recover certain costs not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

The Utilities and ATSI recognize, as regulatory assets, costs which the FERC, the PUCO, the PPUC and the NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. Regulatory assets that do not earn a current return totaled approximately $133 million as of December 31, 2008 (JCP&L - $61 million and Met-Ed - $72 million). Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) are expected to be recovered by 2014 for JCP&L and by 2020 for Met-Ed. The following table discloses regulatory assets by company:

Regulatory Assets*	December 31, 2008	December 31, 2007	Decrease
		(In millions)	
OE	$ 575	$ 737	$ (162)
CEI	784	871	(87)
TE	109	204	(95)
JCP&L	1,228	1,596	(368)
Met-Ed	413	523	(110)
ATSI	31	42	(11)
Total	$ 3,140	$ 3,973	$ (833)

* Penelec had net regulatory liabilities of approximately $137 million and $49 million as of December 31, 2008 and December 31, 2007, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

Regulatory assets by source are as follows:

Regulatory Assets By Source	December 31, 2008	December 31, 2007	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 1,452	$ 2,405	$ (953)
Customer shopping incentives	420	516	(96)
Customer receivables for future income taxes	245	295	(50)
Loss on reacquired debt	51	57	(6)
Employee postretirement benefits	31	39	(8)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(57)	(129)	72
Asset removal costs	(215)	(183)	(32)
MISO/PJM transmission costs	389	340	49
Fuel costs - RCP	214	220	(6)
Distribution costs - RCP	475	321	154
Other	135	92	43
Total	$ 3,140	$ 3,973	$ (833)

Ohio

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

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

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

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

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

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

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

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

Pennsylvania

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company's credit profile would no longer be expected to support an investment grade rating for their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

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

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

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

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;

- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;

- utilities must provide for the installation of smart meter technology within 15 years;

- a minimum reduction in peak demand of 4.5% by May 31, 2013;

- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and

- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

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

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

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

New Jersey

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

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

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact us or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

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

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

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

- reduce peak demand for electricity by 5,700 MW by 2020;

- meet 30% of the state's electricity needs with renewable energy by 2020;

- examine smart grid technology and develop additional cogeneration and other generation resources consistent with the state's greenhouse gas targets; and

- invest in innovative clean energy technologies and businesses to stimulate the industry's growth in New Jersey.

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

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

FERC Matters

Transmission Service between MISO and PJM

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

PJM Transmission Rate Design

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

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

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

Post Transition Period Rate Design

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

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

Interconnection Agreement with AMP-Ohio

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

Duquesne's Request to Withdraw from PJM

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

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

Complaint against PJM RPM Auction

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

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

MISO Resource Adequacy Proposal

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

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

FES Sales to Affiliates

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

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

Reliability Initiatives

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (the PUCO, the FERC, the NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, we completed all of the enhancements that were recommended for completion in 2004. We are also proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

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

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

In April 2007, Reliability*First* performed a routine compliance audit of our bulk-power system within the MISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, Reliability*First* performed a routine compliance audit of our bulk-power system within the PJM region and a final report is expected in early 2009. We currently do not expect any material adverse financial impact as a result of these audits.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate us with regard to air and water quality and other environmental matters. The effects of compliance on us with regard to environmental matters could have a material adverse effect on our earnings and competitive position to the extent that we compete with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. We estimate capital expenditures for environmental compliance of approximately $608 million for the period 2009-2013.

We accrue environmental liabilities only when we conclude that it is probable that we have an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in our determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

Clean Air Act Compliance

We are required to meet federally-approved 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. We believe we are currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

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

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

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_X and SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be \$506 million for 2009-2010 (with \$414 million expected to be spent in 2009). This amount is included in the estimated capital expenditures for environmental compliance referenced above, but excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

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

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

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

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

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

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

National Ambient Air Quality Standards

In March 2005, the EPA finalized the CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR requires reductions of NO_X and 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 just 2.5 million tons annually and NO_X emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of 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 United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to “de-list” coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

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

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity – the ratio of emissions to economic output – by 18% through 2012. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, the EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies. President Obama has announced his Administration's “New Energy for America Plan” that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

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

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate 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. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO_2 under the CAA.

We cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions could require significant capital and other expenditures. The CO_2 emissions per KWH of electricity generated by us is lower than many regional competitors due to our diversified generation sources, which include low or non-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 our plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to our operations. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. We are studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

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

Regulation of Hazardous Waste

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. The EPA subsequently determined that regulation of coal ash as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate non-hazardous waste.

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

The Utilities have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $90 million have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately $56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four of New Jersey's electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial Court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial Court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision in July 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of JCP&L transformers in Red Bank, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court and a case management conference with the presiding Judge was held on June 13, 2008. At that conference, the plaintiffs stated their intent to drop their efforts to create a class-wide damage model and, instead of dismissing the class action, expressed their desire for a bifurcated trial on liability and damages. The judge directed the plaintiffs to indicate, on or before August 22, 2008, how they intend to proceed under this scenario. Thereafter, the judge expects to hold another pretrial conference to address plaintiffs' proposed procedure. JCP&L has received the plaintiffs' proposed plan of action, and intends to file its objection to the proposed plan, and also file a renewed motion to decertify the class. JCP&L is defending this action but is unable to predict the outcome. No liability has been accrued as of December 31, 2008.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours, and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. In a letter dated January 30, 2009, the NERC submitted a written "Notice of Request for Information" (NOI) to JCP&L. The NOI asked for additional factual details about the December 9 event, which JCP&L provided in its response. JCP&L is not able to predict what actions, if any, the NERC may take in response to JCP&L's NOI submittal.

Nuclear Plant Matters

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

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively.

Other Legal Matters

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

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs also sought injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint, which OE opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. Plaintiffs appealed the Court's denial of the motion for certification as a class action which the Ohio Court of Appeals (7th District) denied on December 11, 2008. The period to file a notice of appeal to the Ohio Supreme Court has expired.

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

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

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

CRITICAL ACCOUNTING POLICIES

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

Revenue Recognition

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

Regulatory Accounting

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

Ohio Transition Cost Amortization

In connection with the Ohio Companies' transition plan, the PUCO determined allowable transition costs based on amounts recorded on the regulatory books of the Ohio Companies. These costs exceeded those deferred or capitalized on our balance sheet prepared under GAAP since they included certain costs which had not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). We use an effective interest method for amortizing the Ohio Companies' transition costs (OE's and TE's amortization was complete as of December 31, 2008), often referred to as a "mortgage-style" amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each respective company. In computing the transition cost amortization, we include only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received. Amortization of deferred customer shopping incentives and interest costs are equal to the related revenue recovery that is recognized under the RCP (see Note 2(A)).

Pension and Other Postretirement Benefits Accounting

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

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

In accordance with SFAS 87 and SFAS 106, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. SFAS 87 and SFAS 106 delay recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants' experience.

In December 2006, we adopted SFAS 158 which requires a net liability or asset to be recognized for the overfunded or underfunded status of our defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. We will continue to apply the provisions of SFAS 87 and SFAS 106 in measuring plan assets and benefit obligations as of the balance sheet date and in determining the amount of net periodic benefit cost. The underfunded status of our qualified and non-qualified pension and OPEB plans at December 31, 2008 is $1.7 billion.

In selecting an assumed discount rate, we consider currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed discount rate was 7.0%, 6.5%, and 6.0% as of December 31, 2008, 2007, and 2006, respectively.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. In 2008 our qualified pension and OPEB plan assets actually lost $1.4 billion or 23.8% and earned $481 million or 8.9% in 2007. Our qualified pension and OPEB costs in 2008 and 2007 were computed using an assumed 9.0% rate of return on plan assets which generated $514 million and $499 million of expected returns on plan assets, respectively. The expected return of pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension and OPEB cost, respectively.

Our qualified and non-qualified pension and OPEB net periodic benefit cost was a credit of $116 million in 2008 and $73 million in 2007 compared to costs of $115 million in 2006. On January 2, 2007, we made a $300 million voluntary contribution to our pension plan. In addition, during 2006, we amended our OPEB plan, effective in 2008, to cap our monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. We expect our 2009 qualified and non-qualified pension and OPEB costs (including amounts capitalized) to be $238 million.

Health care cost trends continue to increase and will affect future OPEB costs. The 2008 and 2007 composite health care trend rate assumptions were approximately 9-11%, gradually decreasing to 5% in later years. In determining our trend rate assumptions, we included the specific provisions of our health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in our health care plans, and projections of future medical trend rates. The effect on our pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by 0.25%	$ 14	$ 3	$ 17
Long-term return on assets	Decrease by 0.25%	$ 9	$ 1	$ 10
Health care trend rate	Increase by 1%	n/a	$ 7	$ 7

Emission Allowances

We hold emission allowances for 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

In accordance with SFAS 144, we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, we recognize a loss – calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

The calculation of future cash flows is based on assumptions, estimates and judgment about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Asset Retirement Obligations

In accordance with SFAS 143 and FIN 47, we recognize an ARO for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all of our long-lived assets. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants' current license, settlement based on an extended license term and expected remediation dates.

Income Taxes

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

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, we evaluate goodwill for impairment at least annually and make such evaluations more frequently if indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated, we recognize a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. The forecasts used in our evaluations of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 141(R) – "Business Combinations"

In December 2007, the FASB issued SFAS 141(R), which: (i) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction; (ii) establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and (iii) requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations we enter into that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in deferred tax valuation allowances and income tax uncertainties made after January 1, 2009, that were established as part of a business combination prior to the implementation of this Standard. Under SFAS 141(R), adjustments to the acquired entity's deferred tax assets and uncertain tax position balances occurring outside the measurement period will be recorded as a component of income tax expense, rather than goodwill. The impact of our application of this Standard in periods after implementation will be dependent upon the nature of acquisitions at that time.

SFAS 160 - "Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on our financial statements.

SFAS 161 - "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133"

In March 2008, the FASB issued SFAS 161 that enhances the current disclosure framework for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The FASB believes that additional required disclosure of the fair values of derivative instruments and their gains and losses in a tabular format will provide a more complete picture of the location in an entity's financial statements of both the derivative positions existing at period end and the effect of using derivatives during the reporting period. Disclosing information about credit-risk-related contingent features is designed to provide information on the potential effect on an entity's liquidity from using derivatives. This Statement also requires cross-referencing within the footnotes to help users of financial statements locate important information about derivative instruments. The Statement is effective for reporting periods beginning after November 15, 2008. We expect this Standard to increase our disclosure requirements for derivative instruments and hedging activities.

EITF Issue No. 08-6 – "Equity Method Investment Accounting Considerations"

In November 2008, the FASB issued EITF 08-6, which clarifies how to account for certain transactions involving equity method investments. It provides guidance in determining the initial carrying value of an equity method investment, accounting for a change in an investment from equity method to cost method, assessing the impairment of underlying assets of an equity method investment, and accounting for an equity method investee's issuance of shares. This statement is effective for transactions occurring in fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is not permitted. The impact of our application of this Standard in periods after implementation will be dependent upon the nature of future investments accounted for under the equity method.

FSP SFAS 132 (R)-1 – "Employers' Disclosures about Postretirement Benefit Plan Assets"

In December 2008, the FASB issued Staff Position (FSP) SFAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. Requirements of this FSP include disclosures about investment policies and strategies, categories of plan assets, fair value measurements of plan assets, and significant categories of risk. This FSP is effective for fiscal years ending after December 15, 2009. We expect this Staff Position to increase our disclosure requirements for postretirement benefit plan assets.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

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

The Company's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 60.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common stockholders' equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 9) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 3).

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

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

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	(In millions, except per share amounts)		
REVENUES:			
Electric utilities	$ 12,061	$ 11,305	$ 10,007
Unregulated businesses	1,566	1,497	1,494
Total revenues*	13,627	12,802	11,501
EXPENSES:			
Fuel	1,340	1,178	1,212
Purchased power	4,291	3,836	3,041
Other operating expenses	3,042	3,086	2,965
Provision for depreciation	677	638	596
Amortization of regulatory assets	1,053	1,019	861
Deferral of new regulatory assets	(316)	(524)	(500)
General taxes	778	754	720
Total expenses	10,865	9,987	8,895
OPERATING INCOME	2,762	2,815	2,606
OTHER INCOME (EXPENSE):			
Investment income, net (Note 5(B))	59	120	149
Interest expense	(754)	(775)	(721)
Capitalized interest	52	32	26
Subsidiaries' preferred stock dividends	-	-	(7)
Total other expense	(643)	(623)	(553)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,119	2,192	2,053
INCOME TAXES	777	883	795
INCOME FROM CONTINUING OPERATIONS	1,342	1,309	1,258
Discontinued operations (net of income tax benefits of $2 million) (Note 8)	-	-	(4)
NET INCOME	$ 1,342	$ 1,309	$ 1,254
BASIC EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	$ 4.41	$ 4.27	$ 3.85
Discontinued operations (Note 8)	-	-	(0.01)
Net earnings per basic share	$ 4.41	$ 4.27	$ 3.84
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	304	306	324
DILUTED EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	$ 4.38	$ 4.22	$ 3.82
Discontinued operations (Note 8)	-	-	(0.01)
Net earnings per diluted share	$ 4.38	$ 4.22	$ 3.81
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	307	310	327

* Includes $432 million, $425 million and $400 million of excise tax collections in 2008, 2007 and 2006, respectively.

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

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

As of December 31,	2008	2007
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 545	$ 129
Receivables-		
Customers (less accumulated provisions of $28 million and $36 million, respectively, for uncollectible accounts)	1,304	1,256
Other (less accumulated provisions of $9 million and $22 million, respectively, for uncollectible accounts)	167	165
Materials and supplies, at average cost	605	521
Prepaid taxes	283	32
Other	149	127
	3,053	2,230
PROPERTY, PLANT AND EQUIPMENT:		
In service	26,482	24,619
Less - Accumulated provision for depreciation	10,821	10,348
	15,661	14,271
Construction work in progress	2,062	1,112
	17,723	15,383
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,708	2,127
Investments in lease obligation bonds (Note 6)	598	717
Other	711	754
	3,017	3,598
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,575	5,607
Regulatory assets	3,140	3,973
Pension assets (Note 3)	-	700
Power purchase contract asset	434	215
Other	579	605
	9,728	11,100
	$ 33,521	$ 32,311
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 2,476	$ 2,014
Short-term borrowings (Note 13)	2,397	903
Accounts payable	794	777
Accrued taxes	333	408
Other	1,098	1,046
	7,098	5,148
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 375,000,000 shares- 304,835,407 outstanding	31	31
Other paid-in capital	5,473	5,509
Accumulated other comprehensive loss	(1,380)	(50)
Retained earnings	4,159	3,487
Total common stockholders' equity	8,283	8,977
Long-term debt and other long-term obligations (Note 11(C))	9,100	8,869
	17,383	17,846
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,163	2,671
Asset retirement obligations	1,335	1,267
Deferred gain on sale and leaseback transaction	1,027	1,060
Power purchase contract liability	766	1,018
Retirement benefits	1,884	894
Lease market valuation liability	308	663
Other	1,557	1,744
	9,040	9,317
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 14)		
	$ 33,521	$ 32,311

The accompanying Notes to Consolidated Financial Statements are an integral part of these balance sheets.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Comprehensive Income	Common Stock 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, 2006		329,836,276	$ 33	$ 7,043	$ (20)	$ 2,159	$ (27)
Net income	$ 1,254					1,254	
Unrealized gain on derivative hedges, net of $10 million of income taxes	19				19		
Unrealized gain on investments, net of $40 million of income taxes	69				69		
Comprehensive income	$ 1,342						
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits (Note 3)					(327)		
Redemption premiums on preferred stock						(9)	
Stock options exercised				(28)			
Allocation of ESOP shares				33			17
Restricted stock units				11			
Stock-based compensation				6			
Repurchase of common stock		(10,630,759)	(1)	(599)			
Cash dividends declared on common stock						(598)	
Balance, December 31, 2006		319,205,517	32	6,466	(259)	2,806	(10)
Net income	$ 1,309					1,309	
Unrealized loss on derivative hedges, net of $8 million of income tax benefits	(17)				(17)		
Unrealized gain on investments, net of $31 million of income taxes	47				47		
Pension and other postretirement benefits, net of $169 million of income taxes (Note 3)	179				179		
Comprehensive income	$ 1,518						
Stock options exercised				(40)			
Allocation of ESOP shares				26			10
Restricted stock units				23			
Stock-based compensation				2			
FIN 48 cumulative effect adjustment						(3)	
Repurchase of common stock		(14,370,110)	(1)	(968)			
Cash dividends declared on common stock						(625)	
Balance, December 31, 2007		304,835,407	31	5,509	(50)	3,487	-
Net income	$ 1,342					1,342	
Unrealized loss on derivative hedges, net of $16 million of income tax benefits	(28)				(28)		
Change in unrealized gain on investments, net of $86 million of income tax benefits	(146)				(146)		
Pension and other postretirement benefits, net of $697 million of income tax benefits (Note 3)	(1,156)				(1,156)		
Comprehensive income	$ 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	$ -

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 1,342	$ 1,309	$ 1,254
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	677	638	596
Amortization of regulatory assets	1,053	1,019	861
Deferral of new regulatory assets	(316)	(524)	(500)
Nuclear fuel and lease amortization	112	101	90
Deferred purchased power and other costs	(226)	(346)	(445)
Deferred income taxes and investment tax credits, net	366	(9)	159
Investment impairment (Note 2(E))	123	26	27
Deferred rents and lease market valuation liability	(95)	(99)	(113)
Stock based compensation	(64)	(39)	(37)
Accrued compensation and retirement benefits	(140)	(37)	193
Gain on asset sales	(72)	(30)	(49)
Electric service prepayment programs	(77)	(75)	(64)
Cash collateral, net	(31)	(68)	(77)
Pension trust contributions	-	(300)	-
Decrease (increase) in operating assets-			
Receivables	(29)	(136)	105
Materials and supplies	(52)	79	(25)
Prepaid taxes	(251)	27	(20)
Increase (decrease) in operating liabilities-			
Accounts payable	10	51	99
Accrued taxes	(39)	71	(175)
Accrued interest	4	(8)	7
Other	(76)	44	53
Net cash provided from operating activities	2,219	1,694	1,939
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,367	1,520	2,731
Short-term borrowings, net	1,494	-	386
Redemptions and Repayments-			
Common stock	-	(969)	(600)
Preferred stock	-	-	(193)
Long-term debt	(1,034)	(1,070)	(2,512)
Short-term borrowings, net	-	(205)	-
Net controlled disbursement activity	10	(1)	(27)
Other	14	(1)	(3)
Common stock dividend payments	(671)	(616)	(586)
Net cash provided from (used for) financing activities	1,180	(1,342)	(804)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,888)	(1,633)	(1,315)
Proceeds from asset sales	72	42	162
Proceeds from sale and leaseback transaction	-	1,329	-
Sales of investment securities held in trusts	1,656	1,294	1,651
Purchases of investment securities held in trusts	(1,749)	(1,397)	(1,666)
Cash investments and restricted funds (Note 5)	60	72	121
Other	(134)	(20)	(62)
Net cash used for investing activities	(2,983)	(313)	(1,109)
Net increase in cash and cash equivalents	416	39	26
Cash and cash equivalents at beginning of year	129	90	64
Cash and cash equivalents at end of year	$ 545	$ 129	$ 90
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 667	$ 744	$ 656
Income taxes	$ 685	$ 710	$ 688

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, FENOC, FES and its subsidiaries FGCO and NGC, and FESC.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, the PUCO, PPUC and NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FirstEnergy consolidates a VIE (see Note 7) when it is determined to be the VIE's primary beneficiary. Investments in non-consolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control (20-50% owned companies, joint ventures and partnerships) are accounted for under the equity method. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income.

Certain prior year amounts have been reclassified to conform to the current year presentation. In the fourth quarter of 2008, FirstEnergy determined that certain NUG contracts should be reflected at fair value, with offsetting regulatory assets or liabilities. The December 31, 2007, balance sheet has been revised to record a derivative asset of $215 million, offset by a regulatory liability. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION

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

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

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

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities with the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

Regulatory Assets

The Utilities and ATSI recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to expense as incurred. Regulatory assets that do not earn a current return (primarily for certain regulatory transition costs and employee postretirement benefits) totaled approximately $133 million as of December 31, 2008 (JCP&L - $61 million and Met-Ed - $72 million). Regulatory assets not earning a current return will be recovered by 2014 for JCP&L and by 2020 for Met-Ed.

Regulatory assets on the Consolidated Balance Sheets are comprised of the following:

	2008	2007
	(In millions)	
Regulatory transition costs	$ 1,452	$ 2,405
Customer shopping incentives	420	516
Customer receivables for future income taxes	245	295
Loss on reacquired debt	51	57
Employee postretirement benefits	31	39
Nuclear decommissioning, decontamination and spent fuel disposal costs	(57)	(129)
Asset removal costs	(215)	(183)
MISO/PJM transmission costs	389	340
Fuel costs - RCP	214	220
Distribution costs - RCP	475	321
Other	135	92
Total*	$ 3,140	$ 3,973

* Penelec had net regulatory liabilities of approximately $137 million and $49 million as of December 31, 2008 and December 31, 2007, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

In accordance with the Ohio Companies' RCP, recovery of the aggregate of the regulatory transition costs and the Extended RTC (deferred customer shopping incentives and interest costs) amounts were completed for OE and TE as of December 31, 2008. CEI's recovery of regulatory transition costs is projected to be complete by April 2009, at which time recovery of its Extended RTC will begin, with recovery estimated to be complete as of December 31, 2010. At the end of its recovery period, any of CEI's remaining unamortized regulatory transition costs and Extended RTC balances will be reduced by applying any remaining cost of removal regulatory liability balances; any further remaining regulatory transition costs and Extended RTC balances will be written off. The RCP allowed the Ohio Companies to defer and capitalize certain distribution costs during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the years 2006, 2007 and 2008. In addition, the Ohio Companies deferred certain fuel costs through December 31, 2007 that were incurred above the amount collected through a fuel recovery mechanism in accordance with the RCP (see Note 10(B)).

Transition Cost Amortization

CEI amortizes transition costs using the effective interest method. Extended RTC amortization, beginning in mid-2009, will be equal to the related revenue recovery that is recognized. CEI's estimated net amortization of regulatory transition costs and Extended RTC amounts (including associated carrying charges) under the RCP is expected to be $216 million in 2009 and $273 million in 2010 (see Note 10(B)).

Total regulatory assets for transition costs as of December 31, 2008 were $1.5 billion, of which approximately $1.2 billion and $12 million apply to JCP&L and Met-Ed, respectively. JCP&L's and Met-Ed's regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of $555 million for JCP&L (recovered through BGS and NUGC revenues) and $67 million for Met-Ed (recovered through CTC revenues). Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey and Pennsylvania (See Note 10).

(B) REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Utilities' retail customers are metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided between the last meter reading and the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2008 with respect to any particular segment of FirstEnergy's customers. Total customer receivables were $1.3 billion (billed – $752 million and unbilled – $552 million) and $1.3 billion (billed – $732 million and unbilled – $524 million) as of December 31, 2008 and 2007, respectively.

(C) EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock is computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program. The initial purchase price was $600 million, or $56.44 per share. A final purchase price adjustment of $27 million was settled in cash on April 2, 2007. On March 2, 2007, FirstEnergy repurchased approximately 14.4 million shares, or 4.5%, of its outstanding common stock through an additional accelerated share repurchase program at an initial price of approximately $900 million. A final purchase price adjustment of $51 million was settled in cash on December 13, 2007. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	**2008**	**2007**	**2006**
	(In millions,	*except per share*	*amounts)*
Income from continuing operations	$ 1,342	$ 1,309	$ 1,258
Less: Redemption premium on subsidiary preferred stock	-	-	(9)
Income from continuing operations available to common shareholders	1,342	1,309	1,249
Discontinued operations	-	-	(4)
Net income available for common shareholders	$ 1,342	$ 1,309	$ 1,245
Average shares of common stock outstanding – Basic	304	306	324
Assumed exercise of dilutive stock options and awards	3	4	3
Average shares of common stock outstanding – Diluted	307	310	327
Earnings per share:			
Basic earnings per share:			
Earnings from continuing operations	$ 4.41	$ 4.27	$ 3.85
Discontinued operations	-	-	(0.01)
Net earnings per basic share	$ 4.41	$ 4.27	$ 3.84
Diluted earnings per share:			
Earnings from continuing operations	$ 4.38	$ 4.22	$ 3.82
Discontinued operations	-	-	(0.01)
Net earnings per diluted share	$ 4.38	$ 4.22	$ 3.81

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value in accordance with SFAS 144), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred. Property, plant and equipment balances as of December 31, 2008 and 2007 were as follows:

Property, Plant and Equipment	December 31, 2008 Unregulated	Regulated	Total	December 31, 2007 Unregulated	Regulated	Total
			(In millions)			
In service	$ 10,236	$ 16,246	$ 26,482	$ 8,795	$ 15,824	$ 24,619
Less accumulated depreciation	(4,403)	(6,418)	(10,821)	(4,037)	(6,311)	(10,348)
Net plant in service	$ 5,833	$ 9,828	$ 15,661	$ 4,758	$ 9,513	$ 14,271

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's subsidiaries' electric plant in 2008, 2007 and 2006 are shown in the following table:

	Annual Composite Depreciation Rate 2008	2007	2006
OE	3.1%	2.9%	2.8%
CEI	3.5	3.6	3.2
TE	3.6	3.9	3.8
Penn	2.4	2.3	2.6
JCP&L	2.3	2.1	2.1
Met-Ed	2.3	2.3	2.3
Penelec	2.5	2.3	2.3
FGCO	4.7	4.0	4.1
NGC	2.8	2.8	2.7

Asset Retirement Obligations

FirstEnergy recognizes a liability for retirement obligations associated with tangible assets in accordance with SFAS 143 and FIN 47. These standards require recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and depreciated over time, as described further in Note 12.

Nuclear Fuel

Property, plant and equipment includes nuclear fuel recorded at original cost, which includes material, enrichment, fabrication and interest costs incurred prior to reactor load. Nuclear fuel is amortized based on the units of production method.

(E) ASSET IMPAIRMENTS

Long-Lived Assets

FirstEnergy evaluates the carrying value of its long-lived assets when events or circumstances indicate that the carrying amount may not be recoverable. In accordance with SFAS 144, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If an impairment exists, a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is estimated by using available market valuations or the long-lived asset's expected future net discounted cash flows. The calculation of expected cash flows is based on estimates and assumptions about future events.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its goodwill for impairment at least annually and more frequently as indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated, FirstEnergy recognizes a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill.

The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. FirstEnergy's goodwill primarily relates to its energy delivery services segment. The impairment analysis includes a significant source of cash representing the Utilities' recovery of transition costs as described in Note 10.

FirstEnergy's 2008 annual review was completed in the third quarter of 2008 with no impairment indicated. Due to the significant downturn in the U.S. economy during the fourth quarter of 2008, goodwill was tested for impairment as of an interim date (December 31, 2008). No impairment was indicated for the former GPU companies. As discussed in Note 10(B) on February 19, 2009, the Ohio Companies filed an application for an amended ESP, which substantially reflects terms proposed by the PUCO Staff on February 2, 2009. Goodwill for the Ohio Companies was tested as of December 31, 2008, reflecting the projected results associated with the amended ESP. No impairment was indicated for the Ohio Companies. If the PUCO's final decision authorizes less revenue recovery than the amounts assumed, an additional impairment analysis will be performed at that time that could result in future goodwill impairment. During 2008, FirstEnergy adjusted goodwill of the former GPU companies by $32 million due to the realization of tax benefits that had been reserved under purchase accounting.

FirstEnergy's 2007 annual review was completed in the third quarter of 2007, with no impairment indicated. In the third quarter of 2007, FirstEnergy adjusted goodwill for the former GPU companies by $290 million due to the realization of tax benefits that had been reserved in purchase accounting.

FirstEnergy's 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. The PPUC issued its order on January 11, 2007 related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated that the rate increase ultimately granted could be substantially lower than the amounts requested. As a result of the polling, FirstEnergy determined that an interim review of goodwill for its energy delivery services segment would be required. No impairment was indicated as a result of that review.

A summary of the changes in FirstEnergy's goodwill for the three years ended December 31, 2008 is shown below by segment (see Note 15 - Segment Information):

	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other	Consolidated
			(In millions)		
Balance as of January 1, 2006	$ 5,932	$ 24	$ -	$ 54	$ 6,010
Non-core asset sales				(53)	(53)
Adjustments related to GPU acquisition	(1)				(1)
Adjustments related to Centerior acquisition	(58)				(58)
Balance as of December 31, 2006	5,873	24	-	1	5,898
Adjustments related to GPU acquisition	(290)				(290)
Other				(1)	(1)
Balance as of December 31, 2007	5,583	24	-	-	5,607
Adjustments related to GPU acquisition	(32)				(32)
Balance as of December 31, 2008	$ 5,551	$ 24	$ -	$ -	$ 5,575

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for impairment. In accordance with SFAS 115, FSP SFAS 115-1 and SFAS 124-1, investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other than temporary, the cost basis of the investment is written down to fair value. Upon adoption of FSP SFAS 115-1 and SFAS 124-1, FirstEnergy began recognizing in earnings the unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. The fair value of FirstEnergy's investments are disclosed in Note 5(B).

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity, except those resulting from transactions with stockholders and from the adoption of SFAS 158 in December 2006. As of December 31, 2008, AOCL consisted of a net liability for unfunded retirement benefits net of income tax benefits (see Note 3) of $1.3 billion, unrealized gains on investments in available-for-sale securities of $45 million and unrealized losses on derivative instrument hedges of $103 million. A summary of the changes in FirstEnergy's AOCL balance for the three years ended December 31, 2008 is shown below:

	2008	2007	2006
		(In millions)	
AOCL balance as of January 1	$ (50)	$ (259)	$ (20)
Pension and other postretirement benefits:			
Prior service credit	(126)	(135)	-
Actuarial gain (loss)	(1,725)	483	-
Unrealized gain (loss) on available for sale securities	(232)	78	109
Unrealized gain (loss) on derivative hedges	(43)	(25)	29
Other comprehensive income (loss)	(2,126)	401	138
Income taxes (benefits) related to OCI	(796)	192	50
Other comprehensive income (loss), net of tax	(1,330)	209	88
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits	-	-	(327)
AOCL balance as of December 31	$ (1,380)	$ (50)	$ (259)

Other comprehensive income (loss) reclassified to net income in the three years ended December 31, 2008 is as follows:

	2008	2007	2006
		(In millions)	
Pension and other postretirement benefits, net of income taxes of $32 million and $20 million, respectively	$ 48	$ 25	$ -
Gain on available for sale securities, net of income taxes of $16 million, $4 million and $11 million, respectively	24	6	16
Loss on derivative hedges, net of income tax benefits of $7 million, $10 million and $12 million, respectively	(12)	(16)	(20)
	$ 60	$ 15	$ (4)

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. On January 2, 2007, FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan. In December 2008, The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA) was enacted. Among other provisions, the WRERA provides temporary funding relief to defined benefit plans in light of the current economic crisis. It is expected that the WRERA will have a favorable impact on the level of minimum required contributions for years after 2009. FirstEnergy estimates that additional cash contributions will not be required before 2011.

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

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2008.

Obligations and Funded Status As of December 31	Pension Benefits 2008	Pension Benefits 2007	Other Benefits 2008	Other Benefits 2007
		(In millions)		
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,750	$ 5,031	$ 1,182	$ 1,201
Service cost	87	88	19	21
Interest cost	299	294	74	69
Plan participants' contributions	-	-	25	23
Plan amendments	6	-	(20)	-
Medicare retiree drug subsidy	-	-	2	-
Actuarial (gain) loss	(152)	(381)	12	(30)
Benefits paid	(290)	(282)	(105)	(102)
Benefit obligation as of December 31	$ 4,700	$ 4,750	$ 1,189	$ 1,182
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 5,285	$ 4,818	$ 618	$ 607
Actual return on plan assets	(1,251)	438	(152)	43
Company contribution	8	311	54	47
Plan participants' contribution	-	-	25	23
Benefits paid	(290)	(282)	(105)	(102)
Fair value of plan assets as of December 31	$ 3,752	$ 5,285	$ 440	$ 618
Qualified plan	$ (774)	$ 700		
Non-qualified plans	(174)	(165)		
Funded status	$ (948)	$ 535	$ (749)	$ (564)
Accumulated benefit obligation	$ 4,367	$ 4,397		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ -	$ 700	$ -	$ -
Current liabilities	(8)	(7)	-	-
Noncurrent liabilities	(940)	(158)	(749)	(564)
Net asset (liability) as of December 31	$ (948)	$ 535	$ (749)	$ (564)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 80	$ 83	$ (912)	$ (1,041)
Actuarial loss	2,182	623	801	635
Net amount recognized	$ 2,262	$ 706	$ (111)	$ (406)
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	7.00%	6.50%	7.00%	6.50%
Rate of compensation increase	5.20%	5.20%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	47%	61%	56%	69%
Debt securities	38	30	38	27
Real estate	9	7	2	2
Private equities	3	1	1	-
Cash	3	1	3	2
Total	100%	100%	100%	100%

Estimated Items to be Amortized in 2009 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$ 13	$ (151)
Actuarial loss	$ 170	$ 63

Components of Net Periodic Benefit Costs	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
			(In millions)			
Service cost	$ 87	$ 88	$ 87	$ 19	$ 21	$ 34
Interest cost	299	294	276	74	69	105
Expected return on plan assets	(463)	(449)	(396)	(51)	(50)	(46)
Amortization of prior service cost	13	13	13	(149)	(149)	(76)
Recognized net actuarial loss	8	45	62	47	45	56
Net periodic cost	$ (56)	$ (9)	$ 42	$ (60)	$ (64)	$ 73

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
Discount rate	6.50%	6.00%	5.75%	6.50%	6.00%	5.75%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	5.20%	3.50%	3.50%			

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy generally employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2008	2007
Health care cost trend rate assumed for next year (pre/post-Medicare)	8.5-10%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2015-2017	2015-2017

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 4	$ (3)
Effect on accumulated postretirement benefit obligation	$ 36	$ (32)

Taking into account estimated employee future service, FirstEnergy expects to make the following pension benefit payments from plan assets and other benefit payments, net of the Medicare subsidy and participant contributions:

	Pension Benefits	Other Benefits
	(In millions)	
2009	$ 302	$ 85
2010	309	89
2011	314	94
2012	325	96
2013	338	99
Years 2014- 2018	1,906	524

4. STOCK-BASED COMPENSATION PLANS

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

Effective January 1, 2006, FirstEnergy adopted SFAS 123(R), which requires the expensing of stock-based compensation. Under SFAS 123(R), all share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as an expense over the employee's requisite service period. FirstEnergy adopted the modified prospective method, under which compensation expense recognized in the year ended December 31, 2006 included the expense for all share-based payments granted prior to, but not yet vested, as of January 1, 2006. Results for prior periods were not restated.

(A) LTIP

FirstEnergy's LTIP includes four stock-based compensation programs – restricted stock, restricted stock units, stock options, and performance shares. During 2005, FirstEnergy began issuing restricted stock units and reduced its use of stock options.

Under FirstEnergy's LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2008, 8.7 million shares were available for future awards.

FirstEnergy records the actual tax benefit realized for tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2008, 2007, and 2006 were $43 million, $34 million, and $31 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded to stockholder's equity and reported as an other financing activity within the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

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

	2008	2007	2006
Restricted common shares granted	82,607	77,388	229,271
Weighted average market price	$ 68.98	$ 67.98	$ 53.18
Weighted average vesting period (years)	5.03	4.61	4.47
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during the year was as follows:

Restricted Stock	Number Of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2008	639,657	$ 48.69
Nonvested as of December 31, 2008	667,933	49.54
Vested in 2008	54,331	69.07

FirstEnergy grants two types of restricted stock unit awards -- discretionary-based and performance-based. With the discretionary-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in each agreement. With performance-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in the agreement subject to adjustment based on FirstEnergy's stock performance.

	2008	2007	2006
Restricted common share units granted	450,683	412,426	440,676
Weighted average vesting period (years)	3.14	3.22	3.32

Vesting activity for restricted stock units during the year was as follows:

Restricted Stock Units	Number Of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2008	1,208,780	$ 51.09
Nonvested as of December 31, 2008	1,278,536	55.14
Granted during 2008	450,683	67.09
Vested in 2008	492,229	68.58

Compensation expense recognized in 2008, 2007 and 2006 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $29 million, $24 million and $15 million, respectively.

Stock Options

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

Stock Option Activities	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2006	8,866,256	$ 33.57
(4,090,829 options exercisable)		31.97
Options granted	-	-
Options exercised	2,221,417	32.65
Options forfeited	26,550	33.36
Balance, December 31, 2006	6,618,289	33.88
(4,160,859 options exercisable)		32.85
Options granted	-	-
Options exercised	1,902,780	32.51
Options forfeited	9,575	38.39
Balance, December 31, 2007	4,705,934	34.42
(3,915,694 options exercisable)		33.55
Options granted	-	-
Options exercised	1,438,201	34.10
Options forfeited	1,325	38.76
Balance, December 31, 2008	3,266,408	34.56
(3,266,408 options exercisable)		34.56

Options outstanding by plan and range of exercise price as of December 31, 2008 were as follows:

		Options Outstanding and Exercisable		
Program	Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life
FE Plan	$19.31 - $29.87	1,153,849	$29.10	3.31
	$30.17 - $39.46	2,094,624	$37.65	4.68
GPU Plan	$23.75 - $35.92	17,935	$24.51	1.35
Total		3,266,408	$34.56	4.18

As noted above, FirstEnergy reduced its use of stock options beginning in 2005 and increased its use of performance-based, restricted stock units. FirstEnergy did not accelerate out-of-the-money options in anticipation of adopting SFAS 123(R) on January 1, 2006. As a result, all unvested stock options vested in 2008. Compensation expense recognized for stock options during 2008 was not material. Cash received from the exercise of stock options in 2008, 2007 and 2006 was $74 million, $88 million and $92 million, respectively.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock performance to a composite of peer companies. Compensation expense recognized for performance shares during 2008, 2007 and 2006, net of amounts capitalized, totaled approximately $8 million, $20 million and $25 million, respectively. Cash used to settle performance shares in 2008, 2007 and 2006 was $14 million, $10 million and $7 million, respectively.

(B) ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy's 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP. Between 1990 and 1991, the ESOP borrowed $200 million from OE and acquired 10,654,114 shares of OE's common stock (subsequently converted to FirstEnergy common stock) through market purchases. The ESOP loan was paid in full in 2008. Dividends on ESOP shares were used to service the debt. Dividends on common stock held by the ESOP and used to service debt were $11 million as of December 31, 2007 and 2006. Shares were released from the ESOP on a pro-rata basis as debt service payments were made.

In 2007 and 2006, 521,818 shares and 922,978 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. All shares had been allocated as of December 31, 2007. In 2008, shares of FirstEnergy common stock were purchased on the market and contributed to participants' accounts. Total ESOP-related compensation expense in 2008, 2007 and 2006, net of amounts capitalized and dividends on common stock, was $40 million, $28 million and $27 million, respectively.

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units or into an unfunded retirement cash account. An additional 20% premium is received in the form of stock units based on the amount allocated to the FirstEnergy stock account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Of the 1.3 million EDCP stock units authorized, 504,909 stock units were available for future awards as of December 31, 2008. Compensation expense (income) recognized on EDCP stock units, net of amounts capitalized, was approximately ($13) million in 2008, $7 million in 2007 and $5 million in 2006, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. If the funds are deferred into the stock account, a 20% match is added to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control, or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. DCPD expenses recognized in each of 2008, 2007 and 2006 were approximately $3 million. The net liability recognized for DCPD of approximately $5 million as of December 31, 2008 and 2007 is included in the caption “Retirement benefits” on the Consolidated Balance Sheets.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption "short-term borrowings." The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as shown in the table in Note 11(C) as of December 31:

	2008		2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$ 11,585	$ 11,146	$ 10,891	$ 11,131

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to the FirstEnergy subsidiaries' ratings.

(B) INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities. The Utilities and NGC periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold the investment until recovery and then consider, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment.

Available-For-Sale Securities

The Utilities and NGC hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are classified as available-for-sale with the fair value representing quoted market prices. FirstEnergy has no securities held for trading purposes.

The following table provides the fair value of investments in available-for-sale securities as of December 31, 2008 and 2007. The fair value was determined using the specific identification method.

	2008	2007
	(In millions)	
Debt securities:		
-Government obligations [(1)]	$ 953	$ 851
-Corporate debt securities	175	191
-Mortgage-backed securities	6	17
	1,134	1,059
Equity securities	628	1,355
	$ 1,762	$ 2,414

(1) Excludes $244 million and $3 million of cash in 2008 and 2007, respectively.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities as of December 31:

	2008				2007			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$ 1,082	$ 56	$ 4	$ 1,134	$ 1,036	$ 27	$ 4	$ 1,059
Equity securities	589	39	-	628	995	360	-	1,355
	$ 1,671	$ 95	$ 4	$ 1,762	$ 2,031	$ 387	$ 4	$ 2,414

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2008 were as follows:

	2008	2007	2006
		(In millions)	
Proceeds from sales	$ 1,656	$ 1,294	$ 1,651
Realized gains	115	103	121
Realized losses	237	53	105
Interest and dividend income	76	80	70

Unrealized gains applicable to OE's, TE's and the majority of NGC's decommissioning trusts are recognized in OCI in accordance with SFAS 115, as fluctuations in fair value will eventually impact earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory assets or liabilities since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries.

Held-To-Maturity Securities

The following table provides the approximate fair value and related carrying amounts of investments in held-to-maturity securities (except for investments of $265 million and $314 million for 2008 and 2007, respectively, which are excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments") as of December 31:

	2008		2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Lease obligations bonds	$ 598	$ 599	$ 717	$ 814
Debt securities	75	75	73	73
Notes receivable	45	44	45	43
Restricted funds	1	1	3	3
Equity securities	27	27	29	29
	$ 746	$ 746	$ 867	$ 962

The fair value of investments in lease obligation bonds is based on the present value of the cash inflows based on the yield to maturity. The maturity dates range from 2009 to 2017. The carrying value of the restricted funds is assumed to approximate market value. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2009 to 2016.

The following table provides the amortized cost basis, unrealized gains and losses, and fair values of investments in held-to-maturity securities excluding the restricted funds and notes receivable as of December 31:

	2008				2007			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities	$ 673	$ 14	$ 13	$ 674	$ 790	$ 97	$ -	$ 887
Equity securities	27	-	-	27	29	-	-	29
	$ 700	$ 14	$ 13	$ 701	$ 819	$ 97	$ -	$ 916

(C) SFAS 157 ADOPTION

Effective January 1, 2008, FirstEnergy adopted SFAS 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities recognized at fair value. FirstEnergy also adopted SFAS 159 on January 1, 2008, which provides the option to measure certain financial assets and financial liabilities at fair value. FirstEnergy has analyzed its financial assets and financial liabilities within the scope of SFAS 159 and, as of December 31, 2008, has elected not to record eligible assets and liabilities at fair value.

As defined in SFAS 157, fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. FirstEnergy's Level 1 assets and liabilities primarily consist of exchange-traded derivatives and equity securities listed on active exchanges that are held in various trusts.

Level 2 – Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. FirstEnergy's Level 2 assets and liabilities consist primarily of investments in debt securities held in various trusts and commodity forwards. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

Level 3 – Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the longer term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate FirstEnergy management. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. FirstEnergy's Level 3 instruments consist of NUG contracts.

FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The following table sets forth FirstEnergy's financial assets and financial liabilities that are accounted for at fair value by level within the fair value hierarchy as of December 31, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FirstEnergy's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	December 31, 2008			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In millions)		
Assets:				
Derivatives	$ -	$ 40	$ -	$ 40
Nuclear decommissioning trusts[1]	537	1,166	-	1,703
NUG contracts[2]	-	-	434	434
Other investments	19	381	-	400
Total	$ 556	$ 1,587	$ 434	$ 2,577
Liabilities:				
Derivatives	$ 25	$ 31	$ -	$ 56
NUG contracts[2]	-	-	766	766
Total	$ 25	$ 31	$ 766	$ 822

(1) Balance excludes $5 million of net receivables, payables and accrued income.
(2) NUG contracts are completely offset by regulatory assets.

The determination of the above fair value measures takes into consideration various factors required under SFAS 157. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

Exchange-traded derivative contracts, which include some futures and options, are generally based on unadjusted quoted market prices in active markets and are classified within Level 1. Forwards, options and swap contracts that are not exchange-traded are classified as Level 2 as the fair values of these items are based on Intercontinental Exchange quotes or market transactions in the OTC markets. In addition, complex or longer-term structured transactions can introduce the need for internally-developed model inputs that may not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is classified as Level 3.

Nuclear decommissioning trusts consist of equity securities listed on active exchanges classified as Level 1 and various debt securities and collective trusts classified as Level 2. Other investments represent the NUG trusts, spent nuclear fuel trusts and rabbi trust investments, which primarily consist of various debt securities and collective trusts classified as Level 2.

The following tables provide a reconciliation of changes in the fair value of NUG contracts classified as Level 3 in the fair value hierarchy during 2008 (in millions):

Balance as of January 1, 2008	$	(803)
Settlements[1]		278
Unrealized gains (losses)[1]		193
Net transfers to (from) Level 3		-
Balance as of December 31, 2008	$	(332)
Change in unrealized gains (losses) relating to instruments held as of December 31, 2008	$	193

(1) Changes in the fair value of NUG contracts are completely offset by regulatory assets and do not impact earnings.

Under FSP FAS 157-2, “Effective Date of FASB Statement No. 157”, FirstEnergy deferred until January 1, 2009, the election of SFAS 157 for financial assets and financial liabilities measured at fair value on a non-recurring basis and is currently evaluating the impact of SFAS 157 on those financial assets and financial liabilities.

(D) DERIVATIVES

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

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales criteria. Derivatives that meet that criteria are accounted for using traditional accrual accounting. The changes in the fair value of derivative instruments that do not meet the normal purchase and normal sales criteria are recorded as other expense, as AOCL, or as part of the value of the hedged item, depending on whether or not it is designated as part of a hedge transaction, the nature of the hedge transaction and hedge effectiveness.

FirstEnergy hedges anticipated transactions using cash flow hedges. Such transactions include hedges of anticipated electricity and natural gas purchases, capital assets denominated in foreign currencies and anticipated interest payments associated with future debt issues. Other than interest-related hedges, FirstEnergy's maximum hedge term is typically two years. The effective portions of all cash flow hedges are initially recorded in equity as other comprehensive income or loss and are subsequently included in net income as the underlying hedged commodities are delivered or interest payments are made. Gains and losses from any ineffective portion of cash flow hedges are included directly in earnings.

The net deferred losses of $103 million included in AOCL as of December 31, 2008, for derivative hedging activity, as compared to $75 million as of December 31, 2007, resulted from a net $40 million increase related to current hedging activity and a $12 million decrease due to net hedge losses reclassified to earnings during 2008. Based on current estimates, approximately $28 million (after tax) of the net deferred losses on derivative instruments in AOCL as of December 31, 2008 are expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuate from period to period based on various market factors.

FirstEnergy has entered into swaps that have been designated as fair value hedges of fixed-rate, long-term debt issues to protect against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. In order to reduce counterparty exposure and lessen variable debt exposure under current market conditions, FirstEnergy unwound its remaining interest rate swaps. During 2008, FirstEnergy received $3 million to terminate interest rate swaps with an aggregate notional value of $250 million. As of December 31, 2008, FirstEnergy had no outstanding interest rate swaps hedging fixed-rate long term debt.

During 2008, FirstEnergy entered into several forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the anticipated issuances of fixed-rate, long-term debt securities for one or more of its subsidiaries as outstanding debt matures during 2008 and 2009. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During 2008, FirstEnergy entered into swaps with a notional value of $1.3 billion and terminated swaps with a notional value of $1.4 billion for which it paid $49 million, $7 million of which was deemed ineffective and recognized in current period earnings. FirstEnergy will recognize the remaining $42 million loss over the life of the associated future debt. As of December 31, 2008, FirstEnergy had forward swaps with an aggregate notional amount of $300 million and a fair value of $(3) million.

6. LEASES

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

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

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

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

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

Rentals for capital and operating leases for the three years ended December 31, 2008 are summarized as follows:

	2008	2007	2006
		(In millions)	
Operating leases			
Interest element	$ 194	$ 180	$ 160
Other	187	196	190
Capital leases			
Interest element	1	-	1
Other(1)	6	1	2
Total rentals	$ 388	$ 377	$ 353

(1) Includes $5 million in 2008 of wind purchased power agreements classified as capital leases in accordance with EITF 01-8.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 7).

The future minimum lease payments as of December 31, 2008 are:

	Operating Leases		
	Lease Payments	Capital Trusts	Net
		(In millions)	
2009	$ 310	$ 107	$ 203
2010	293	116	177
2011	288	116	172
2012	331	125	206
2013	337	130	207
Years thereafter	2,746	254	2,492
Total minimum lease payments	$ 4,305	$ 848	$ 3,457

The present value of net minimum capital lease payments for FirstEnergy as of December 31, 2008, is $8 million, of which $1 million is classified as a current liability.

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

FirstEnergy has recorded above-market lease liabilities for the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The total above-market lease obligation of $755 million associated with the Bruce Mansfield Plant is being amortized on a straight-line basis through the end of 2016 (approximately $46 million per year). As of December 31, 2008, the above-market lease liabilities for the Bruce Mansfield Plant totaled $353 million, of which $46 million is classified in the caption "other current liabilities."

7. VARIABLE INTEREST ENTITIES

FIN 46R addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the entity's residual economic risks and rewards. FirstEnergy and its subsidiaries consolidate VIEs when they are determined to be the VIE's primary beneficiary as defined by FIN 46R.

Mining Operations

On July 16, 2008, FEV entered into a joint venture with the Boich Companies, a Columbus, Ohio-based coal company, to acquire a majority stake in the Signal Peak mining and coal transportation operations near Roundup, Montana. FirstEnergy made a $125 million equity investment in the joint venture, which acquired 80% of the mining operations (Signal Peak Energy, LLC) and 100% of the transportation operations, with FEV owning a 45% economic interest and an affiliate of the Boich Companies owning a 55% economic interest in the joint venture. Both parties have a 50% voting interest in the joint venture. After January 2010, the joint venture will have 18 months to exercise an option to acquire the remaining 20% stake in the mining operations. In accordance with FIN 46R, FirstEnergy consolidated the mining and transportation operations of this joint venture in its financial statements.

Trusts

FirstEnergy's consolidated financial statements include those of PNBV and Shippingport. VIEs created in 1996 and 1997, respectively, to refinance debt originally issued in connection with sale and leaseback transactions described above. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE.

Loss Contingencies

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

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(in millions)	
FES	$ 1,349	$ 1,182	$ 167
OE	778	574	204
CEI	713	81	632
TE	713	419	294

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments was $1.7 billion as of December 31, 2008 (see NGC lessor equity interest purchases described in Note 6).

See Note 6 for a discussion of CEI's and TE's assignment of their leasehold interests in the Bruce Mansfield Plant to FGCO.

Power Purchase Agreements

In accordance with FIN 46R, FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to FirstEnergy's utility subsidiaries and the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed, and Penelec, maintains approximately 30 long-term power purchase agreements with NUG entities. The agreements were entered into pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but eight of these entities, neither JCP&L, Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. JCP&L, Met-Ed or Penelec may hold variable interests in the remaining eight entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants. As required by FIN 46R, FirstEnergy periodically requests from these eight entities the information necessary to determine whether they are VIEs or whether JCP&L, Met-Ed or Penelec is the primary beneficiary. FirstEnergy has been unable to obtain the requested information, which in most cases was deemed by the requested entity to be proprietary. As such, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R.

Since FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. Purchased power costs from these entities during 2008, 2007, and 2006 were $178 million, $177 million, and $171 million, respectively.

8. DIVESTITURES AND DISCONTINUED OPERATIONS

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

In 2006, FirstEnergy sold certain of its remaining FSG subsidiaries for an aggregate net after-tax gain of $2.2 million. In addition, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of $0.2 million in March 2006. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounted for its remaining interest under the equity method of accounting for investments. In the fourth quarter of 2006, FirstEnergy sold its remaining MYR interest for an after-tax gain of $8.6 million. The income for the period that MYR was accounted for as an equity method investment has not been included in discontinued operations; however, results for all reporting periods prior to the initial sale in March 2006, including the gain on the sale, were reported as discontinued operations.

Revenues associated with discontinued operations were $225 million in 2006. The following table summarizes the net income operating results of discontinued operations for 2006:

	2006 (In millions)
Loss before income taxes	$ (8)
Income tax benefit	2
Gain on sale, net of tax	2
Loss from discontinued operations	$ (4)

9. TAXES

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and loss carryforwards and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2008 are shown below:

For the Years Ended December 31,	2008	2007 (In millions)	2006
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	$ 355	$ 706	$ 519
State	56	187	116
	411	893	635
Deferred, net-			
Federal	343	22	147
State	36	(18)	28
	379	4	175
Investment tax credit amortization	(13)	(14)	(15)
Total provision for income taxes	$ 777	$ 883	$ 795
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ 2,119	$ 2,192	$ 2,053
Federal income tax expense at statutory rate	$ 742	$ 767	$ 719
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(13)	(14)	(15)
State income taxes, net of federal income tax benefit	60	110	94
Other, net	(12)	20	(3)
Total provision for income taxes	$ 777	$ 883	$ 795

Accumulated deferred income taxes as of December 31, 2008 and 2007 are as follows:

As of December 31,	2008	2007
	(In millions)	
Property basis differences	$ 2,757	$ 2,564
Regulatory transition charge	292	468
Pension and other postretirement obligations	(715)	(110)
Nuclear decommissioning activities	(130)	(13)
Customer receivables for future income taxes	145	149
Deferred customer shopping incentive	151	190
Deferred MISO/PJM transmission costs	167	151
Other regulatory assets - RCP	253	193
Unrealized losses on derivative hedges	(68)	(52)
Deferred sale and leaseback gain	(505)	(536)
Nonutility generation costs	(52)	(90)
Unamortized investment tax credits	(51)	(57)
Lease market valuation liability	(254)	(283)
Oyster Creek securitization (Note 11(C))	137	149
Loss carryforwards	(35)	(44)
Loss carryforward valuation reserve	27	31
All other	44	(39)
Net deferred income tax liability	$ 2,163	$ 2,671

On January 1, 2007, FirstEnergy adopted FIN 48, which provides guidance for accounting for uncertainty in income taxes in a company's financial statements in accordance with SFAS 109. This interpretation prescribes a financial statement recognition threshold and measurement attribute for tax positions taken or expected to be taken on a company's tax return. FIN 48 also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

As of January 1, 2007, the total amount of FirstEnergy's unrecognized tax benefits was $268 million. FirstEnergy recorded a $2.7 million cumulative effect adjustment to the January 1, 2007 balance of retained earnings to increase reserves for uncertain tax positions. Upon completion of the federal tax examinations for tax years 2004-2006, as well as other tax settlements reached in 2008, FirstEnergy recognized approximately $42 million of net tax benefits, including $7 million that favorably affected FirstEnergy's effective tax rate. The remaining balance of the tax benefits recognized in 2008 adjusted goodwill as a purchase price adjustment ($20 million) and accumulated deferred income taxes for temporary tax items ($15 million). During 2007, there were no material changes to FirstEnergy's unrecognized tax benefits. As of December 31, 2008, FirstEnergy expects that it is reasonably possible that approximately $151 million of the unrecognized benefits may be resolved within the next twelve months, of which approximately $147 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to the capitalization of certain costs, capital gains and losses recognized on the disposition of assets and various other tax items.

A reconciliation of the change in the unrecognized tax benefits for the years 2008 and 2007 are as follows:

	2008	2007
	(In millions)	
Balance at beginning of year	$ 272	$ 268
Increase for tax positions related to the current year	14	1
Increase for tax positions related to prior years	-	3
Decrease for tax positions related to prior years	(56)	-
Decrease for settlements	(11)	-
Balance at end of year	$ 219	$ 272

FIN 48 also requires companies to recognize interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes, consistent with its policy prior to implementing FIN 48. The reversal of accrued interest associated with the $56 million in recognized tax benefits favorably affected FirstEnergy's effective tax rate in 2008 by $12 million and an interest receivable of $4 million was removed from the accrued interest for FIN 48 items. During the years ended December 31, 2008, 2007 and 2006, FirstEnergy recognized net interest expense of approximately $2 million, $19 million and $9 million, respectively. The net amount of interest accrued as of December 31, 2008 and 2007 was $59 million and $53 million, respectively.

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

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity (see Note 6). This transaction generated tax capital gains of approximately $815 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowance in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $987 million of which $140 million is expected to be utilized. The associated deferred tax assets are $8 million. These losses expire as follows:

Expiration Period	Amount *(In millions)*
2009-2013	$ 195
2014-2018	3
2019-2023	492
2024-2028	297
	$ 987

General Taxes

Details of general taxes for the three years ended December 31, 2008 are shown below:

For the Years Ended December 31,	2008	2007	2006
		(In millions)	
Real and personal property	$ 240	$ 237	$ 222
Kilowatt-hour excise	249	250	241
State gross receipts	183	175	159
Social security and unemployment	95	87	83
Other	11	5	15
Total general taxes	$ 778	$ 754	$ 720

Commercial Activity Tax

On June 30, 2005, tax legislation was enacted in the State of Ohio that created a new CAT tax, which is based on qualifying "taxable gross receipts" and does not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaced the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income-based franchise tax was computed consistent with the prior tax law, except that the tax liability as computed was multiplied by 80% in 2005; 60% in 2006; 40% in 2007 and 20% in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that were not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005.

10. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (the PUCO, the FERC, the NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, FirstEnergy completed all of the enhancements that were recommended for completion in 2004. FirstEnergy is also proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

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

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

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

(B) OHIO

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

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

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

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

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

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

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

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

(C) PENNSYLVANIA

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company's credit profile would no longer be expected to support an investment grade rating for their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

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

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

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

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;
- a minimum reduction in peak demand of 4.5% by May 31, 2013;
- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

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

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

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

(D) NEW JERSEY

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

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

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

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

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

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

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

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

(E) FERC MATTERS

Transmission Service between MISO and PJM

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

PJM Transmission Rate Design

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

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

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

Post Transition Period Rate Design

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

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

Interconnection Agreement with AMP-Ohio

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

Duquesne's Request to Withdraw from PJM

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

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

Complaint against PJM RPM Auction

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

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

MISO Resource Adequacy Proposal

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

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

FES Sales to Affiliates

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

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

11. CAPITALIZATION

(A) COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2008, FirstEnergy's unrestricted retained earnings were $4.2 billion. Dividends declared in 2008 were $2.20, which included four quarterly dividends of $0.55 per share paid in the second, third and fourth quarters of 2008 and payable in the first quarter of 2009. Dividends declared in 2007 were $2.05, which included three quarterly dividends of $0.50 per share paid in the second, third and fourth quarters of 2007 and a quarterly dividend of $0.55 per share paid in the first quarter of 2008. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, each of FirstEnergy's electric utility subsidiaries has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. The articles of incorporation, indentures and various other agreements relating to the long-term debt and preferred stock of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. With the exception of Met-Ed, which is currently in an accumulated deficit position, none of these provisions materially restricted FirstEnergy's subsidiaries' ability to pay cash dividends to FirstEnergy as of December 31, 2008.

(B) PREFERRED AND PREFERENCE STOCK

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

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

No preferred shares or preference shares are currently outstanding. The following table details the change in preferred shares outstanding during 2006. No shares were issued in 2007 or 2008.

	Not Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value
	(Dollars in millions)	
Balance, January 1, 2006	3,785,699	$ 184
Redemptions-		
3.90% Series	(152,510)	(15)
4.40% Series	(176,280)	(18)
4.44% Series	(136,560)	(14)
4.56% Series	(144,300)	(14)
4.24% Series	(40,000)	(4)
4.25% Series	(41,049)	(4)
4.64% Series	(60,000)	(6)
$4.25 Series	(160,000)	(16)
$4.56 Series	(50,000)	(5)
$4.25 Series	(100,000)	(10)
$2.365 Series	(1,400,000)	(35)
Adjustable Series B	(1,200,000)	(30)
4.00% Series	(125,000)	(13)
Balance, December 31, 2006	-	$ -

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

The following table presents the outstanding long-term debt and other long-term obligations of FirstEnergy as of December 31, 2008 and 2007:

	Weighted Average Interest Rate (%)	December 31, 2008	December 31, 2007
		(In millions)	
FMBs:			
Due 2008-2013	6.08	$ 29	$ 155
Due 2014-2018	8.84	330	5
Due 2019-2023	7.91	7	7
Due 2024-2028	5.95	14	14
Due 2034-2038	8.25	275	-
Total FMBs		655	181
Secured Notes:			
Due 2008-2013	7.50	607	385
Due 2014-2018	7.25	613	522
Due 2019-2023	5.89	70	70
Due 2024-2028	-	-	25
Due 2029-2033	-	-	82
Total Secured Notes		1,290	1,084
Unsecured Notes:			
Due 2008-2013	6.12	2,253	2,360
Due 2014-2018	5.65	2,149	2,185
Due 2019-2023	2.90	689	689
Due 2024-2028	4.54	65	40
Due 2029-2033	5.83	2,247	2,162
Due 2034-2038	5.03	1,936	1,935
Due 2039-2043	1.29	255	255
Due 2044-2048	3.38	46	-
Total Unsecured Notes		9,640	9,626
Total		11,585	10,891
Capital lease obligations		8	4
Net unamortized discount on debt		(17)	(12)
Long-term debt due within one year		(2,476)	(2,014)
Total long-term debt and other long-term obligations		$ 9,100	$ 8,869

Securitized Transition Bonds

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

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. As of December 31, 2008, $369 million of the transition bonds were outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property.

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

Other Long-term Debt

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

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

Based on the amount of FMBs authenticated by the respective mortgage bond trustees through December 31, 2008, the Utilities' annual sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to $34 million. Penn expects to deposit funds with its mortgage bond trustee in 2009 that will then be withdrawn upon the surrender for cancellation of a like principal amount of FMBs, specifically authenticated for such purposes against unfunded property additions or against previously retired FMBs. This method can result in minor increases in the amount of the annual sinking fund requirement. Met-Ed and Penelec could fulfill their sinking fund obligations by providing bondable property additions, previously retired FMBs or cash to the respective mortgage bond trustees.

As of December 31, 2008, FirstEnergy's currently payable long-term debt includes approximately $2.2 billion (FES - $2.0 billion, OE - $100 million, Met-Ed - $29 million and Penelec - $45 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

Prior to the third quarter of 2008, FirstEnergy subsidiaries had not experienced any unsuccessful remarketings of these variable-rate PCRBs. Coincident with recent disruptions in the variable-rate demand bond and capital markets generally, certain of the PCRBs had been tendered by bondholders to the trustee. As of January 31, 2009, all PCRBs that had been tendered were successfully remarketed.

In February 2009, holders of approximately $434 million in principal of LOC-supported PCRBs of NGC were notified that the applicable Wachovia Bank LOCs expire on March 18, 2009. As a result, these PCRBs are subject to mandatory purchase at a price equal to the principal amount, plus accrued and unpaid interest, which FES and NGC expect to fund through short-term borrowings. Subject to market conditions, FES and NGC expect to remarket or refinance these PCRBs during the remainder of 2009.

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

	(In millions)
2009	$ 2,475
2010	322
2011	1,617
2012	160
2013	563

Included in the table above are amounts for the variable interest rate PCRBs described above. These amounts are $2.2 billion, $15 million, $25 million and $56 million in 2009, 2010, 2011 and 2012, respectively, representing the next time the debt holders may exercise their right to tender their PCRBs.

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs of $2.1 billion as of December 31, 2008, or noncancelable municipal bond insurance of $39 million as of December 31, 2008, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs or the insurance, FGCO, NGC and the Utilities are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Utilities pay annual fees of 0.35% to 1.70% of the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations.

OE has LOCs of $291 million and $134 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. In 2004, OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of approximately $236 million of the Beaver Valley Unit 2 LOCs and the issuer of the standby LOC obtained the right to pledge or assign participations in OE's reimbursement obligations under the credit agreement to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE.

12. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations under SFAS 143 for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two coal ash disposal sites. In addition, FirstEnergy has recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47.

The ARO liability of $1.3 billion as of December 31, 2008 primarily relates to the nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

FirstEnergy maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2008, the fair value of the decommissioning trust assets was approximately $1.7 billion.

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability, not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143.

The following table describes the changes to the ARO balances during 2008 and 2007.

ARO Reconciliation	**2008**	**2007**
	(In millions)	
Balance at beginning of year	$ 1,267	$ 1,190
Liabilities incurred	5	-
Liabilities settled	(3)	(2)
Accretion	84	79
Revisions in estimated cash flows	(18)	-
Balance at end of year	$ 1,335	$ 1,267

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

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

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

The Utilities, with the exception of TE and JCP&L, each have a wholly owned subsidiary whose borrowings are secured by customer accounts receivable purchased from its respective parent company. The CEI subsidiary's borrowings are also secured by customer accounts receivable purchased from TE. Each subsidiary company has its own receivables financing arrangement and, as a separate legal entity with separate creditors, would have to satisfy its obligations to creditors before any of its remaining assets could be available to its parent company. The receivables financing borrowing commitment by company are shown in the following table. There were no outstanding borrowings as of December 31, 2008.

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
Penn Power Funding LLC	Penn	25	0.60	December 18, 2009
Met-Ed Funding LLC	Met-Ed	80	0.60	December 18, 2009
Penelec Funding LLC	Penelec	75	0.60	December 18, 2009
		$ 550		

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2008 and 2007 were 1.19% and 5.42%, respectively. The annual facility fees on all current committed short-term bank lines of credit range from 0.125% to 0.60%.

14. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to $12.5 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. FirstEnergy's maximum potential assessment under the industry retrospective rating plan would be $470 million per incident but not more than $70 million in any one year for each incident.

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

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

(B) GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. As of December 31, 2008, outstanding guarantees and other assurances aggregated approximately $4.4 billion, consisting of parental guarantees - $1.2 billion, subsidiaries' guarantees - $2.6 billion, surety bonds - $0.1 billion and LOCs - $0.5 billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.4 billion (included in the $1.2 billion discussed above) as of December 31, 2008 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2008, FirstEnergy's maximum exposure under these collateral provisions was $585 million, consisting of $60 million due to "material adverse event" contractual clauses and $525 million due to a below investment grade credit rating. Additionally, stress case conditions of a credit rating downgrade or "material adverse event" and hypothetical adverse price movements in the underlying commodity markets would increase this amount to $689 million, consisting of $61 million due to "material adverse event" contractual clauses and $628 million due to a below investment grade credit rating.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $95 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' book of business as of December 31, 2008, and forward prices as of that date, FES had $103 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (15% decrease in prices), FES would be required to post an additional $98 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

In July 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases (see Note 6). The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty.

On October 8, 2008, to enhance their liquidity position in the face of the turbulent credit and bond markets, FirstEnergy, FES and FGCO entered into a $300 million secured term loan facility with Credit Suisse. Under the facility, FGCO is the borrower and FES and FirstEnergy are guarantors. Generally, the facility is available to FGCO until October 7, 2009, with a minimum borrowing amount of $100 million and maturity 30 days from the date of the borrowing. Once repaid, borrowings may not be re-borrowed.

Also in October 2008, FirstEnergy negotiated with the banks that have issued irrevocable direct pay LOCs in support of its outstanding variable interest rate PCRBs to extend the respective reimbursement obligations of the applicable FirstEnergy subsidiary obligors in the event that such LOCs are drawn upon. FirstEnergy's subsidiaries currently have approximately $2.1 billion variable interest rate PCRBs outstanding (FES - $1.9 billion, OE - $100 million, Met-Ed - $29 million and Penelec - $45 million). The LOCs supporting these PCRBs may be drawn upon to pay the purchase price to bondholders that have exercised the right to tender their PCRBs for mandatory purchase. Approximately $972 million of LOCs that previously required reimbursement within 30 days or less of a draw under the applicable LOC have now been modified to extend the reimbursement obligations to six months or June 2009, as applicable.

(C) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on FirstEnergy with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. FirstEnergy estimates capital expenditures for environmental compliance of approximately $608 million for the period 2009-2013.

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

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved 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.

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

FirstEnergy complies with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_X reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_X reductions 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 and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be $506 million for 2009-2010 (with $414 million expected to be spent in 2009). This amount is included in the estimated capital expenditures for environmental compliance referenced above, but excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

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

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

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

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

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

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

National Ambient Air Quality Standards

In March 2005, the EPA finalized the CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR requires reductions of NO_X and 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 just 2.5 million tons annually and NO_X emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of 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 United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

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

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity – the ratio of emissions to economic output – by 18% through 2012. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, the EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

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

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate 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. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO_2 under the CAA.

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

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. FirstEnergy is studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

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

Regulation of Hazardous Waste

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. The EPA subsequently determined that regulation of coal ash as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate non-hazardous waste.

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

The Utilities have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $90 million have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately $56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

(D) OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four of New Jersey's electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial Court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial Court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision in July 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of JCP&L transformers in Red Bank, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court and a case management conference with the presiding Judge was held on June 13, 2008. At that conference, the plaintiffs stated their intent to drop their efforts to create a class-wide damage model and, instead of dismissing the class action, expressed their desire for a bifurcated trial on liability and damages. The judge directed the plaintiffs to indicate, on or before August 22, 2008, how they intend to proceed under this scenario. Thereafter, the judge expects to hold another pretrial conference to address plaintiffs' proposed procedure. JCP&L has received the plaintiffs' proposed plan of action, and intends to file its objection to the proposed plan, and also file a renewed motion to decertify the class. JCP&L is defending this action but is unable to predict the outcome. No liability has been accrued as of December 31, 2008.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours, and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. In a letter dated January 30, 2009, the NERC submitted a written "Notice of Request for Information" (NOI) to JCP&L. The NOI asked for additional factual details about the December 9 event, which JCP&L provided in its response. JCP&L is not able to predict what actions, if any, the NERC may take in response to JCP&L's NOI submittal.

Nuclear Plant Matters

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

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively.

Other Legal Matters

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

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs also sought injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint, which OE opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. Plaintiffs appealed the Court's denial of the motion for certification as a class action which the Ohio Court of Appeals (7th District) denied on December 11, 2008. The period to file a notice of appeal to the Ohio Supreme Court has expired.

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

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

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

15. SEGMENT INFORMATION

FirstEnergy has three reportable operating segments: energy delivery services, competitive energy services and Ohio transitional generation services. The assets and revenues for all other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable operating segments."

The energy delivery services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems and is responsible for the regulated generation commodity operations of FirstEnergy's Pennsylvania and New Jersey electric utility subsidiaries. Its revenues are primarily derived from the delivery of electricity, cost recovery of regulatory assets, and default service electric generation sales to non-shopping customers in its Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES under partial requirements purchased power agreements and from non-affiliated power suppliers as well as the net PJM transmission expenses related to the delivery of that generation load.

The competitive energy services segment supplies electric power to its electric utility affiliates, provides competitive electricity sales primarily in Ohio, Pennsylvania, Maryland and Michigan, owns or leases and operates FirstEnergy's generating facilities and purchases electricity to meet its sales obligations. The segment's net income is primarily derived from the affiliated company PSA sales and the non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver electricity to the segment's customers. The segment's internal revenues represent the affiliated company PSA sales.

The Ohio transitional generation services segment represents the regulated generation commodity operations of FirstEnergy's Ohio electric utility subsidiaries. Its revenues are primarily derived from electric generation sales to non-shopping customers under the PLR obligations of the Ohio Companies. Its results reflect the purchase of electricity from the competitive energy services segment through full-requirements PSA arrangements, the deferral and amortization of certain fuel costs authorized for recovery by the energy delivery services segment and the net MISO transmission revenues and expenses related to the delivery of generation load. This segment's total assets consist of accounts receivable for generation revenues from retail customers.

Segment Financial Information	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other	Reconciling Adjustments	Consolidated
			(In millions)			
2008						
External revenues	$ 9,166	$ 1,571	$ 2,902	$ 72	$ (84)	$ 13,627
Internal revenues	-	2,968	-	-	(2,968)	-
Total revenues	9,166	4,539	2,902	72	(3,052)	13,627
Depreciation and amortization	1,090	243	64	4	13	1,414
Investment income	170	(34)	1	6	(84)	59
Net interest charges	407	108	1	2	184	702
Income taxes	555	314	56	(53)	(95)	777
Net income	833	472	83	116	(162)	1,342
Total assets	22,760	9,559	265	539	398	33,521
Total goodwill	5,551	24	-	-	-	5,575
Property additions	839	1,835	-	176	38	2,888
2007						
External revenues	$ 8,726	$ 1,468	$ 2,596	$ 39	$ (27)	$ 12,802
Internal revenues	-	2,901	-	-	(2,901)	-
Total revenues	8,726	4,369	2,596	39	(2,928)	12,802
Depreciation and amortization	1,024	204	(125)	4	26	1,133
Investment income	240	16	1	1	(138)	120
Net interest charges	445	152	1	4	141	743
Income taxes	574	330	69	4	(94)	883
Net income	862	495	103	12	(163)	1,309
Total assets	23,595	7,669	231	303	513	32,311
Total goodwill	5,583	24	-	-	-	5,607
Property additions	814	740	-	21	58	1,633
2006						
External revenues	$ 7,623	$ 1,429	$ 2,390	$ 95	$ (36)	$ 11,501
Internal revenues	14	2,609	-	-	(2,623)	-
Total revenues	7,637	4,038	2,390	95	(2,659)	11,501
Depreciation and amortization	845	190	(105)	4	23	957
Investment income	328	35	-	1	(215)	149
Net interest charges	433	188	1	6	74	702
Income taxes	595	262	75	(21)	(116)	795
Income from continuing operations	893	393	112	44	(184)	1,258
Discontinued operations	-	-	-	(4)	-	(4)
Net income	893	393	112	40	(184)	1,254
Total assets	22,863	6,978	215	297	843	31,196
Total goodwill	5,873	24	-	1	-	5,898
Property additions	629	644	-	4	38	1,315

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses and elimination of intersegment transactions.

*Products and Services**

Year	Electricity Sales	Energy Related Sales and Services
	(In millions)	
2008	$ 12,693	$ -
2007	11,944	-
2006	10,671	48

* See Note 8 for discussion of discontinued operations.

16. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 141(R) – "Business Combinations"

In December 2007, the FASB issued SFAS 141(R), which: (i) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction; (ii) establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and (iii) requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations entered into by FirstEnergy that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in deferred tax valuation allowances and income tax uncertainties made after January 1, 2009, that were established as part of a business combination prior to the implementation of this Standard. Under SFAS 141(R), adjustments to the acquired entity's deferred tax assets and uncertain tax position balances occurring outside the measurement period will be recorded as a component of income tax expense, rather than goodwill. The impact of FirstEnergy's application of this Standard in periods after implementation will be dependent upon the nature of acquisitions at that time.

SFAS 160 - "Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on FirstEnergy's financial statements.

SFAS 161 - "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133"

In March 2008, the FASB issued SFAS 161 that enhances the current disclosure framework for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The FASB believes that additional required disclosure of the fair values of derivative instruments and their gains and losses in a tabular format will provide a more complete picture of the location in an entity's financial statements of both the derivative positions existing at period end and the effect of using derivatives during the reporting period. Disclosing information about credit-risk-related contingent features is designed to provide information on the potential effect on an entity's liquidity from using derivatives. This Statement also requires cross-referencing within the footnotes to help users of financial statements locate important information about derivative instruments. The Statement is effective for reporting periods beginning after November 15, 2008. FirstEnergy expects this Standard to increase its disclosure requirements for derivative instruments and hedging activities.

EITF Issue No. 08-6 – "Equity Method Investment Accounting Considerations"

In November 2008, the FASB issued EITF 08-6, which clarifies how to account for certain transactions involving equity method investments. It provides guidance in determining the initial carrying value of an equity method investment, accounting for a change in an investment from equity method to cost method, assessing the impairment of underlying assets of an equity method investment, and accounting for an equity method investee's issuance of shares. This statement is effective for transactions occurring in fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is not permitted. The impact of FirstEnergy's application of this Standard in periods after implementation will be dependent upon the nature of future investments accounted for under the equity method.

FSP SFAS 132 (R)-1 – "Employers' Disclosures about Postretirement Benefit Plan Assets"

In December 2008, the FASB issued Staff Position (FSP) SFAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. Requirements of this FSP include disclosures about investment policies and strategies, categories of plan assets, fair value measurements of plan assets, and significant categories of risk. This FSP is effective for fiscal years ending after December 15, 2009. FirstEnergy expects this Staff Position to increase its disclosure requirements for postretirement benefit plan assets.

17. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2008 and 2007.

Three Months Ended	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
	(In millions, except per share amounts)			
Revenues	$ 3,277	$ 3,245	$ 3,904	$ 3,201
Expenses	2,660	2,663	3,058	2,484
Operating Income	617	582	846	717
Other Expense	154	159	137	193
Income Before Income Taxes	463	423	709	524
Income Taxes	187	160	238	192
Net Income	$ 276	$ 263	$ 471	$ 332
Earnings Per Share of Common Stock:				
Basic	$ 0.91	$ 0.86	$ 1.55	$ 1.09
Diluted	$ 0.90	$ 0.85	$ 1.54	$ 1.09

Three Months Ended	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
	(In millions, except per share amounts)			
Revenues	$ 2,973	$ 3,109	$ 3,641	$ 3,079
Expenses	2,336	2,381	2,791	2,479
Operating Income	637	728	850	600
Other Expense	147	168	164	144
Income Before Income Taxes	490	560	686	456
Income Taxes	200	222	273	188
Net Income	$ 290	$ 338	$ 413	$ 268
Earnings Per Share of Common Stock:				
Basic	$ 0.92	$ 1.11	$ 1.36	$ 0.88
Diluted	$ 0.92	$ 1.10	$ 1.34	$ 0.87

FIRSTENERGY CORP.

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS
(Unaudited)

For the Years Ended December 31,	2008	2007	2006	2005	2004	2003	1998
GENERAL FINANCIAL INFORMATION							
(Dollars in millions)							
Revenues	$ 13,627	$ 12,802	$ 11,501	$ 11,358	$ 11,600	$ 10,802	$5,875
Net Income	$ 1,342	$ 1,309	$ 1,254	$ 861	$ 878	$ 423	$411
SEC Ratio of Earnings to							
Fixed Charges	3.27	3.21	3.14	2.74	2.64	1.75	1.77
Capital Expenditures	$2,150	$1,496	$1,170	$1,144	$731	$792	$306
Total Capitalization	$ 17,383	$ 17,846	$ 17,570	$17,527	$18,938	$18,414	$11,756
Capitalization Ratios:							
Common Stockholders' Equity	47.7 %	50.3 %	51.4 %	52.4 %	45.3 %	45.0 %	37.9
Preferred and Preference Stock:							
Not Subject to Mandatory Redemption	-	-	-	1.1	1.8	1.8	5.6
Subject to Mandatory Redemption	-	-	-	-	-	-	2.5
Long-Term Debt	52.3	49.7	48.6	46.5	52.9	53.2	54.0
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%	6.47%	8.01%
Long-Term Debt	5.95%	5.89%	6.33%	6.05%	5.93%	6.08%	7.83%
COMMON STOCK DATA							
Earnings per Share (a):							
Basic	$ 4.41	$ 4.27	$ 3.85	$ 2.68	$ 2.77	$ 1.46	$ 1.95
Diluted	$ 4.38	$ 4.22	$ 3.82	$ 2.67	$ 2.76	$ 1.46	$ 1.95
Return on Average Common Equity (a)	14.7%	14.9%	13.5%	10.0%	10.8%	5.9%	10.3%
Dividends Paid per Share	$ 2.20	$ 2.00	$ 1.80	$ 1.67	$ 1.50	$ 1.50	$ 1.50
Dividend Payout Ratio (a)	50%	47%	47%	62%	54%	103%	77%
Dividend Yield	4.5%	2.8%	3.0%	3.4%	3.8%	4.3%	4.6%
Price/Earnings Ratio (a)	11.0	17.0	15.7	18.3	14.3	24.1	16.7
Book Value per Share	$ 27.17	$ 29.45	$ 28.35	$ 27.98	$ 26.20	$ 25.35	$ 19.37
Market Price per Share	$ 48.58	$ 72.34	$ 60.30	$ 48.99	$ 39.51	$ 35.20	$ 32.56
Ratio of Market Price to Book Value	179%	246%	213%	175%	151%	139%	168%
OPERATING STATISTICS (b)							
Generation Kilowatt-Hour Sales (Millions):							
Residential	38,845	39,158	37,618	34,716	31,781	31,322	31,220
Commercial	34,405	36,879	35,390	32,878	32,114	32,311	31,033
Industrial	32,345	33,476	34,309	32,907	31,675	32,451	36,683
Other	538	540	542	547	504	554	611
Total Retail	106,133	110,053	107,859	101,048	96,074	96,638	99,547
Total Wholesale	24,654	24,114	23,083	28,521	53,268	42,059	9,910
Total Sales	130,787	134,167	130,942	129,569	149,342	138,697	109,457
Customers Served:							
Residential	3,963,229	3,956,837	3,959,043	3,941,030	3,916,855	3,874,052	3,735,308
Commercial	518,982	517,251	514,056	509,933	500,695	496,253	447,087
Industrial	10,225	10,367	10,458	10,637	10,597	10,871	19,902
Other	6,196	6,054	6,356	6,124	5,654	5,635	5,876
Total	4,498,632	4,490,509	4,489,913	4,467,724	4,433,801	4,386,811	4,208,173
Number of Employees	14,698	14,534	13,739	14,586	15,245	15,905	20,392

(a) Before discontinued operations in 2006, 2005, 2004 and 2003, and accounting changes in 2005 and 2003.
(b) Reflects pro forma combined FirstEnergy and GPU statistics in 1998

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 checks 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 2009 Annual Meeting of Shareholders on Tuesday, May 19, 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 23, 2009.

FirstEnergy has included as Exhibit 31 to its Annual Report on Form 10-K for fiscal year 2008 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. FirstEnergy's Chief Executive Officer has also submitted to the New York Stock Exchange (NYSE) a certificate certifying that he was not aware of any violation by FirstEnergy of the NYSE corporate governance listing standards as of the date of the certification.

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FirstEnergy®

76 South Main Street, Akron, OH 44308-1890

2008 Annual Report