FIRSTENERGY CORP
Form 10-K
February 27, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the FISCAL YEAR ended December 31, 2013

OR

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

For the transition period from ____________________ to ____________________

| Commission File Number | Registrant; State of Incorporation; Address; and Telephone Number | I.R.S. Employer Identification No. |
|---|---|---|
| 333-21011 | FIRSTENERGY CORP.<br>(An Ohio Corporation)<br>76 South Main Street<br>Akron, OH 44308<br>Telephone (800)736-3402 | 34-1843785 |
| 000-53742 | FIRSTENERGY SOLUTIONS CORP.<br>(An Ohio Corporation)<br>c/o FirstEnergy Corp.<br>76 South Main Street<br>Akron, OH 44308<br>Telephone (800)736-3402 | 31-1560186 |

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

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

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

| Registrant | Title of Each Class |
|---|---|
| FirstEnergy Solutions Corp. | Common Stock, no par value per share |

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes þ No o FirstEnergy Corp.
Yes o No þ FirstEnergy Solutions Corp.
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.

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

| | |
|---|---|
| þ | FirstEnergy Corp. |
| o | FirstEnergy Solutions Corp. |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large Accelerated Filer þ | FirstEnergy Corp. |
| Accelerated Filer o | N/A |
| Non-accelerated Filer (Do not check if a smaller reporting company) þ | FirstEnergy Solutions Corp. |
| Smaller Reporting Company o | N/A |

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

Yes o No þ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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

FirstEnergy Corp., $15,570,961,427 as of June 30, 2013; and for FirstEnergy Solutions Corp., none.

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date:

| CLASS | OUTSTANDING AS OF JANUARY 31, 2014 |
|---|---|
| FirstEnergy Corp., $0.10 par value | 418,734,086 |
| FirstEnergy Solutions Corp., no par value | 7 |

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp. common stock.

Documents Incorporated By Reference

| DOCUMENT | PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED |
|---|---|
| Proxy Statement for 2014 Annual Meeting of Shareholders to be held May 20, 2014 | Parts II and III |

This combined Form 10-K is separately filed by FirstEnergy Corp. and FirstEnergy Solutions Corp. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to FirstEnergy Solutions Corp. is also attributed to FirstEnergy Corp.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "will," "intend," “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, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission plan and planned distribution rate cases and the effectiveness of our repositioning strategy.
- The impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases or the WVCAG's pending appeal of the Generation Resource Transaction.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as the polar vortex or other significant weather events.
- Regulatory outcomes associated with storm restoration, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and availability and their impact on retail margins.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water discharge, water intake and coal combustion residual regulations, the potential impacts of CSAPR, CAIR, and/or any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units including the impact on vendor commitments, and the timing thereof as they relate to, among other things, RMR arrangements and the reliability of the transmission grid.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building and the steam generator replacement at Davis-Besse.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- Replacement power costs being higher than anticipated or not fully hedged.
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- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals including, but not limited to, the ability to reduce costs and to successfully complete our announced financial plans designed to improve our credit metrics and strengthen our balance sheet, including but not limited to, the benefits from our announced dividend reduction and our proposed capital raising and debt reduction initiatives.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.
- The ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.

- Actions that may be taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

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GLOSSARY OF TERMS

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

| | |
|---|---|
| AE | Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011 |
| AESC | Allegheny Energy Service Corporation, a subsidiary of AE |
| AE Supply | Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of AE |
| AGC | Allegheny Generating Company, a generation subsidiary of AE Supply |
| Allegheny | Allegheny Energy, Inc., together with its consolidated subsidiaries |
| Allegheny Utilities | MP, PE and WP |
| ATSI | American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities. |
| Buchanan Energy | Buchanan Energy Company of Virginia, LLC |
| CEI | The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary |
| Centerior | Centerior Energy Corp., former parent of CEI and TE, which merged with OE to form FirstEnergy in 1997 |
| FE | FirstEnergy Corp., a public utility holding company |
| FENOC | FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities |
| FES | FirstEnergy Solutions Corp., which provides energy-related products and services |
| FESC | FirstEnergy Service Company, which provides legal, financial and other corporate support services |
| FET | FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, a subsidiary of AE, which is the parent of ATSI and TrAIL and has a joint venture in PATH. |
| FEV | FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures |
| FG | FirstEnergy Generation, LLC, a subsidiary of FES, which owns and operates non-nuclear generating facilities |
| FirstEnergy | FirstEnergy Corp., together with its consolidated subsidiaries |
| Global Holding | Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC |
| Global Rail | A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana |
| GPU | GPU, Inc., former parent of JCP&L, ME and PN, that merged with FirstEnergy on November 7, 2001 |
| JCP&L | Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary |
| ME | Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary |
| Merger Sub | Element Merger Sub, Inc., a Maryland corporation and a wholly owned subsidiary of FirstEnergy |
| MP | Monongahela Power Company, a West Virginia electric utility operating subsidiary of AE |
| NG | FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities |
| OE | Ohio Edison Company, an Ohio electric utility operating subsidiary |
| Ohio Companies | CEI, OE and TE |
| PATH | Potomac-Appalachian Transmission Highline, LLC, a joint venture between Allegheny and a subsidiary of AEP |
| PATH-Allegheny | PATH Allegheny Transmission Company, LLC |
| PATH-WV | PATH West Virginia Transmission Company, LLC |

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| PE | The Potomac Edison Company, a Maryland electric utility operating subsidiary of AE |
| Penn | Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE |
| Pennsylvania Companies | ME, PN, Penn and WP |
| PN | Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary |
| PNBV | PNBV Capital Trust, a special purpose entity created by OE in 1996 |
| Shippingport | Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997 |
| Signal Peak | An indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana |
| TE | The Toledo Edison Company, an Ohio electric utility operating subsidiary |
| TrAIL | Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities |
| Utilities | OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP |
| WP | West Penn Power Company, a Pennsylvania electric utility operating subsidiary of AE |

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

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| AEP | American Electric Power Company, Inc. |
| AFS | Available-for-sale |
| ALJ | Administrative Law Judge |

GLOSSARY OF TERMS, Continued

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|---|---|
| AMT | Alternative Minimum Tax |
| Anker WV | Anker West Virginia Mining Company, Inc. |
| Anker Coal | Anker Coal Group, Inc. |
| AOCI | Accumulated Other Comprehensive Income |
| Apple® | Apple®, iPad® and iPhone® are registered trademarks of Apple Inc. |
| ARO | Asset Retirement Obligation |
| ARR | Auction Revenue Right |
| ASLB | Atomic Safety and Licensing Board |
| BGS | Basic Generation Service |
| BRA | PJM RPM Base Residual Auction |
| CAA | Clean Air Act |
| CAIR | Clean Air Interstate Rule |
| CBA | Collective Bargaining Agreement |
| CBP | Competitive Bid Process |
| CCB | Coal Combustion By-products |
| CCR | Coal Combustion Residuals |
| CDWR | California Department of Water Resources |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act of 1980 |
| CFR | Code of Federal Regulations |
| CFTC | Commodity Futures Trading Commission |
| $CO_2$ | Carbon Dioxide |
| CSAPR | Cross-State Air Pollution Rule |
| CWA | Clean Water Act |
| CWIP | Construction Work in Progress |
| Dayton | The Dayton Power and Light Company |
| DCPD | Deferred Compensation Plan for Outside Directors |
| DCR | Delivery Capital Recovery |
| DOE | United States Department of Energy |
| DOJ | United States Department of Justice |
| DSP | Default Service Plan |
| Duke | Duke Energy Ohio, a subsidiary of Duke Energy Corporation |
| EBO | Early Buyout Option |
| EDC | Electric Distribution Company |
| EDCP | Executive Deferred Compensation Plan |
| EE&C | Energy Efficiency and Conservation |
| EGS | Electric Generation Supplier |
| ELPC | Environmental Law & Policy Center |
| ENEC | Expanded Net Energy Cost |
| EPA | United States Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| ERO | Electric Reliability Organization |
| ESOP | Employee Stock Ownership Plan |
| ESP | Electric Security Plan |
| Facebook® | Facebook is a registered trademark of Facebook, Inc. |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |

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| Fitch | Fitch Ratings |
| FMB | First Mortgage Bond |
| FPA | Federal Power Act |
| FTR | Financial Transmission Right |
| GAAP | Accounting Principles Generally Accepted in the United States of America |

GLOSSARY OF TERMS, Continued

| | |
|---|---|
| GHG | Greenhouse Gases |
| GWH | Gigawatt-hour |
| HCL | Hydrochloric Acid |
| IBEW | International Brotherhood of Electrical Workers |
| ICE | IntercontinentalExchange, Inc. |
| ICG | International Coal Group Inc. |
| ICP | Amended and Restated 2007 Incentive Plan |
| ILP | Integrated License Application Process |
| IRS | Internal Revenue Service |
| kV | Kilovolt |
| KWH | Kilowatt-hour |
| LBR | Little Blue Run |
| LCAPP | Long-Term Capacity Agreement Pilot Program |
| LITE | Local Infrastructure and Transmission Enhancement |
| LOC | Letter of Credit |
| LSE | Load Serving Entity |
| MATS | Mercury and Air Toxics Standards |
| mcf | Million cubic feet |
| MDPSC | Maryland Public Service Commission |
| MISO | Midcontinent Independent System Operator, Inc. |
| mmBTU | One Million British Thermal Units |
| Moody’s | Moody’s Investors Service, Inc. |
| MOPR | Minimum Offer Price Rule |
| MTEP | MISO Regional Transmission Expansion Plan |
| MVP | Multi-Value Project |
| MW | Megawatt |
| MWH | Megawatt-hour |
| NDT | Nuclear Decommissioning Trust |
| NEIL | Nuclear Electric Insurance Limited |
| NERC | North American Electric Reliability Corporation |
| NGO | Non-Governmental Organization |
| NJBPU | New Jersey Board of Public Utilities |
| NMB | Non-Market Based |
| NNSR | Non-Attainment New Source Review |
| NOL | Net Operating Loss |
| NOV | Notice of Violation |
| NOx | Nitrogen Oxide |
| NPDES | National Pollutant Discharge Elimination System |
| NRC | Nuclear Regulatory Commission |
| NSR | New Source Review |
| NUG | Non-Utility Generation |
| NYISO | New York Independent System Operator |
| NYPSC | New York State Public Service Commission |
| NYSEG | New York State Electric and Gas |
| OCC | Ohio Consumers' Counsel |
| OPEB | Other Post-Employment Benefits |

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|---|---|
| OPEIU | Office and Professional Employees International Union |
| OTC | Over The Counter |
| OTTI | Other Than Temporary Impairments |
| OVEC | Ohio Valley Electric Corporation |
| PA DEP | Pennsylvania Department of Environmental Protection |

GLOSSARY OF TERMS, Continued

| | |
|---|---|
| PCB | Polychlorinated Biphenyl |
| PCRB | Pollution Control Revenue Bond |
| PJM | PJM Interconnection LLC |
| PM | Particulate Matter |
| POLR | Provider of Last Resort |
| PPUC | Pennsylvania Public Utility Commission |
| PSA | Power Supply Agreement |
| PSD | Prevention of Significant Deterioration |
| PSEG | Public Service Electric and Gas Company |
| PUCO | Public Utilities Commission of Ohio |
| PURPA | Public Utility Regulatory Policies Act of 1978 |
| R&D | Research and Development |
| RCRA | Resource Conservation and Recovery Act |
| REC | Renewable Energy Credit |
| REIT | Real Estate Investment Trust |
| RFC | ReliabilityFirst Corporation |
| RFP | Request for Proposal |
| RGGI | Regional Greenhouse Gas Initiative |
| RMR | Reliability Must-Run |
| RPM | Reliability Pricing Model |
| RTEP | Regional Transmission Expansion Plan |
| RTO | Regional Transmission Organization |
| S&P | Standard & Poor’s Ratings Service |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SB221 | Amended Substitute Senate Bill 221 |
| SBC | Societal Benefits Charge |
| SEC | United States Securities and Exchange Commission |
| SERTP | Southeastern Regional Transmission Planning |
| $SF_6$ | Sulfur Hexafluoride |
| SIP | State Implementation Plan(s) Under the Clean Air Act |
| SMIP | Smart Meter Implementation Plan |
| $SO_2$ | Sulfur Dioxide |
| SOS | Standard Offer Service |
| SPE | Special Purpose Entity |
| SREC | Solar Renewable Energy Credit |
| SSO | Standard Service Offer |
| TBC | Transition Bond Charge |
| TDS | Total Dissolved Solid |
| TMDL | Total Maximum Daily Load |
| TMI-2 | Three Mile Island Unit 2 |
| TSC | Transmission Service Charge |
| Twitter® | Twitter is a registered trademark of Twitter, Inc. |
| U.S. Court of Appeals for the D.C. Circuit | United States Court of Appeals for the District of Columbia Circuit |
| UWUA | Utility Workers Union of America |

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|---|---|
| VIE | Variable Interest Entity |
| VSCC | Virginia State Corporation Commission |
| WVCAG | West Virginia Citizen Action Group |
| WVDEP | West Virginia Department of Environmental Protection |
| WVPSC | Public Service Commission of West Virginia |

PART I
ITEM 1. BUSINESS
The Company

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FES and its principal subsidiaries (FG and NG), FESC and during 2013, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP, FET and its principal subsidiaries (ATSI, TrAIL and PATH), and AESC). In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc. As of January 1, 2014, AE merged with and into FirstEnergy Corp., therefore, AE's direct subsidiaries, AE Supply, MP, PE, WP and FET, became direct subsidiaries of FirstEnergy Corp.

Subsidiaries

FirstEnergy's revenues are primarily derived from electric service provided by its utility operating subsidiaries (OE, CEI, TE, Penn, ATSI, JCP&L, ME, PN, MP, PE, WP and TrAIL) and the sale of energy and related products and services by its unregulated competitive subsidiaries, FES and AE Supply.

The Utilities' combined service areas encompass approximately 65,000 square miles in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. The areas they serve have a combined population of approximately 13.4 million.

OE was organized under the laws of the State of Ohio in 1930 and owns property and does business as an electric public utility in that state. OE engages in the distribution and sale of electric energy to communities in a 7,000 square mile area of central and northeastern Ohio. The area it serves has a population of approximately 2.3 million. OE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

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

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the distribution and sale of electric energy in an area of 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.7 million. CEI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the distribution and sale of electric energy in an area of 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.7 million. TE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns major, high-voltage transmission facilities, which consist of approximately 7,525 pole miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV in the PJM Region. ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, ATSI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and applicable state regulatory authorities.

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has a 50% ownership interest in a hydroelectric generating facility. JCP&L complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and the NJBPU.

ME was organized under the laws of the Commonwealth of Pennsylvania in 1922 and owns property and does business as an electric public utility in that state. ME provides transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million. ME complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

PN was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. PN provides transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.3 million. PN, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in the Waverly, New York vicinity. PN complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NYPSC and PPUC.

PE was organized under the laws of the State of Maryland in 1923 and in the Commonwealth of Virginia in 1974. PE is authorized to do business in the Commonwealth of Virginia and the States of West Virginia and Maryland. PE owns property and does business as an electric public utility in those states. PE provides transmission and distribution services in 5,500 square miles area in portions of Maryland, Virginia and West Virginia. The area it serves has a population of approximately 0.9 million. PE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, MDPSC, VSCC, and WVPSC.

MP was organized under the laws of the State of Ohio in 1924 and owns property and does business as an electric public utility in the state of West Virginia. MP provides generation, transmission and distribution services in 13,000 square miles of northern West Virginia. The area it serves has a population of approximately 0.8 million. As of December 31, 2013, MP owned or contractually controlled 3,580 MWs of generation capacity that is supplied to its electric utility business. In addition, MP is contractually obligated to provide power to PE to meet its load obligations in West Virginia. MP complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and WVPSC.

WP was organized under the laws of the Commonwealth of Pennsylvania in 1916 and owns property and does business as an electric public utility in that state. WP provides transmission and distribution services in 10,400 square miles of southwestern, south-central and northern Pennsylvania. The area it serves has a population of approximately 1.6 million. WP complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

TrAIL was organized under the laws of the State of Maryland and the Commonwealth of Virginia in 2006. TrAIL was formed to finance, construct, own, operate and maintain high-voltage transmission facilities in the PJM Region and has several transmission facilities in operation at the present time including a 500kV transmission line extending approximately 150 miles from southwestern Pennsylvania through West Virginia to a point of interconnection with Virginia Electric and Power Company in northern Virginia. TrAIL plans, operates and maintains its transmission system and facilities in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, TrAIL complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, and applicable state regulatory authorities.

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

AE Supply was organized under the laws of the State of Delaware in 1999. AE Supply provides energy-related products and services to wholesale and retail customers. AE Supply also owns and operates fossil generating facilities and purchases and sells energy and energy-related commodities.

AGC was organized under the laws of the Commonwealth of Virginia in 1981. AGC is owned approximately 59% by AE Supply and approximately 41% by MP. AGC’s sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. AGC provides the generation capacity from this facility to AE Supply and MP.

FES, FG, NG, AE Supply and AGC comply with the regulations, orders, policies and practices prescribed by the SEC and FERC. In addition, NG and FENOC comply with the regulations, orders, policies and practices prescribed by the NRC.

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

Reference is made to Note 19, Segment Information, of the Combined Notes to Consolidated Financial Statements for information regarding FirstEnergy’s reportable segments, which information is incorporated herein by reference.

Competitive and Regulated Generation

As of February 24, 2014, FirstEnergy’s generating portfolio consists of 17,848 MW of diversified capacity (Competitive — 14,068 MW, including 885 MWs of capacity subject to RMR arrangements with PJM and Regulated — 3,780 MW). Of the generation asset portfolio, approximately 10,113 MW (56.6%), consist of coal-fired capacity; 4,048 MW (22.7%) consist of nuclear capacity; 1,400 MW (7.8%) consist of hydroelectric capacity; 1,603 MW (9.0%) consist of oil and natural gas units; 496 MW (2.8%) consist of wind and solar power arrangements; and 188 MW (1.1%) consist of capacity entitlements to output from generation assets owned by OVEC. All units are located within PJM and sell electric energy, capacity and other products into the wholesale markets that are operated by PJM. Within the Competitive portfolio, 11,086 MW consist of FES' facilities that are operated by FENOC and FG (including entitlements from OVEC, wind and solar power arrangements), except for portions of certain facilities that are subject to the sale and leaseback arrangements with non-affiliates. The corresponding output of these arrangements is available to FES through power sale agreements, and are owned directly by NG and FG, respectively. Another 2,982 MW of the Competitive portfolio consists of AE Supply's facilities, including 713 MW from AGC's Bath County, Virginia hydroelectric facility that AE Supply partially owns and 67 MW of AE Supply's 3.01% entitlement from OVEC's generation output. FES' generating facilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's generating facilities are primarily located in Pennsylvania, West Virginia, Virginia and Ohio.

Within the Regulated portfolio, 200 MW consist of JCP&L's 50% ownership interest in the Yards Creek hydroelectric facility in New Jersey; 3,580 MW consist of MP's facilities, including 487 MW from AGC's Bath County, Virginia hydroelectric facility that MP partially owns and 11 MW of MP's 0.49% entitlement from OVEC's generation output. MP's facilities are concentrated primarily in West Virginia.

Utility Regulation

State Regulation

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

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

Federal Regulation

With respect to their wholesale services and rates, the Utilities, AE Supply, ATSI, AGC, FES, FG, NG, PATH and TrAIL are subject to regulation by FERC. Under the FPA, FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under its open access transmission tariff. See FERC Matters below.

FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, and PE each have been authorized by FERC to sell wholesale power in interstate commerce and have a market-based rates tariff on file with FERC; although major wholesale purchases and sales remain subject to regulation by the relevant state commissions. Moreover, as a condition to selling electricity on a wholesale basis at market-based rates, OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP and PE, like all other entities granted market-based rate authority, must file electronic quarterly reports with FERC listing their sales transactions for the prior quarter. AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each have been authorized by FERC to sell wholesale power in interstate commerce at market-based rates and have a market-based rate tariff on file with FERC. By virtue of these tariffs, each company is regulated as a public utility under the FPA. However, consistent with its historical practice, FERC has granted AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC a waiver from most of the reporting, record-keeping and accounting requirements that typically apply to traditional public utilities. Along with market-based rate authority, FERC also granted AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC blanket authority to issue securities and assume liabilities under Section 204 of the FPA. As a condition to selling electricity on a wholesale basis at market-based rates, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC, like all other entities granted market-based rate authority, must file electronic quarterly reports with FERC, listing their contracts and sales transactions for the prior quarter.

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

Regulatory Accounting

The Utilities, AGC, ATSI, PATH and TrAIL recognize, as regulatory assets and regulatory liabilities, costs which FERC, PUCO, PPUC, MDPSC, WVPSC and NJBPU, as applicable, have authorized for recovery/return from/to customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets and regulatory liabilities would have been charged to income as incurred. All regulatory assets and liabilities are expected to be recovered/returned from/to customers. Based on current ratemaking procedures, the Utilities, ATSI, PATH and TrAIL continue to collect cost-based rates for their transmission and distribution services and, in the case of PATH, for its abandoned plant, which remains regulated; accordingly, it is appropriate that the Utilities, AGC, ATSI, PATH and TrAIL continue the application of regulatory accounting to those operations.

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, ATSI, PATH and TrAIL since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.

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

Reliability Matters

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

Maryland Regulatory Matters

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change.

PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific

SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by May 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

New Jersey Regulatory Matters

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed.

The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On November 15, 2013, the Division of Rate Counsel filed testimony recommending that approximately $15 million of JCP&L’s costs be disallowed for recovery. Evidentiary hearings in this proceeding were scheduled for January 2014 but were subsequently adjourned by the NJBPU before their commencement. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L’s $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

Ohio Regulatory Matters

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on February 24, 2014.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio

Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Ohio Companies recently reported that they met all of their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014.

Pennsylvania Regulatory Matters

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. Hearings on the plans are scheduled to be held March 4-7, 2014. The Pennsylvania Companies expect a decision from the PPUC by August 4, 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC's motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court's decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ’s decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The Office of Consumer Advocate took exception to one issue and both parties filed replies to exceptions on December 12, 2013. The case is now before the PPUC for consideration.
A decision is expected during the first quarter of 2014.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the

Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

West Virginia Regulatory Matters

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed but the WVPSC has not yet issued an opinion in this matter.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. The charge is included in Impairment of long lived assets within the Consolidated Statement of Income. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. In accordance with the settlement, MP and PE will file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the West Virginia Supreme Court. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. Oral argument before the Supreme Court is scheduled for March 5, 2014.

FERC Matters

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision 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 (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated for briefing and disposition before that court. Briefing is complete, and the case will be scheduled for oral argument, with a decision currently expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's separate Order No. 1000 compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, have sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing was completed in December 2013 and oral argument is scheduled for March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility of certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone for the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs to the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In the May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. The case thereafter was briefed and oral arguments took place on December 11, 2013. A decision currently is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August

24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy’s subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. See Note 20, Discontinued Operations and Assets Held for Sale for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, in January 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27,

2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the “joint and common market” stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $65.5 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FES and AE Supply's request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into three categories: (i) Demand Response (DR); (ii) imports; and (iii) modeling of transmission upgrades in calculating geographic clearing prices. The purpose of PJM’s tariff amendments is to ensure that resources that clear in the RPM auctions are available and able to satisfy all obligations under the PJM tariffs. In each of the affected dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC issued deficiency letters requesting additional information from PJM regarding the imports and modeling filings, and on January 30, 2014 accepted the DR filing as proposed. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling and imports filings. PJM's compliance filings and all other filings in the dockets are pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

Capital Requirements

Our capital spending for 2014 is expected to be approximately $3.3 billion (excluding nuclear fuel), which includes spending associated with our announced transmission plan. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives. Our capital investments for additional nuclear fuel are expected to be $238 million in 2014.

Actual capital expenditures for 2013 and anticipated expenditures for 2014, excluding nuclear fuel, are shown in the following table. Such costs include expenditures for the improvement of existing facilities and for the construction of transmission lines, distribution lines and substations, and other assets.

| | 2013 Actual[1] | Capital Expenditures Forecast 2014[2] |
|---|---|---|
| | (In millions) | |
| OE | $138 | $160 |
| Penn | 26 | 34 |
| CEI | 98 | 110 |
| TE | 40 | 39 |
| JCP&L | 238 | 251 |
| ME | 91 | 105 |
| PN | 139 | 174 |
| MP | 131 | 233 |
| PE | 68 | 101 |
| WP | 106 | 138 |
| ATSI | 282 | 1,004 |
| TrAIL | 57 | 147 |
| FG | 123 | 190 |
| NG | 438 | 497 |
| AE Supply | 135 | 47 |
| Other subsidiaries | 103 | 105 |
| Total | $2,213 | $3,335 |

(1) Includes a reduction of approximately ($130) million related to the capital component of the mark-to-market adjustment for pensions and OPEB costs.
(2) Excludes capitalized mark-to-market adjustments for pensions and OPEB costs, which cannot be estimated.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2013, excluding capital leases for the next five years. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2014.

| | 2014 | 2015-2018 | Total |
|---|---|---|---|
| | (In millions) | | |
| FE | $— | $800 | $800 |
| FES | 887 | 1,237 | 2,124 |
| Other[1] | 489 | 3,362 | 3,851 |
| FirstEnergy | $1,376 | $5,399 | $6,775 |

(1) Includes debt of non-registrant subsidiaries and the elimination of certain intercompany debt.

The following tables display consolidated operating lease commitments as of December 31, 2013.

| Operating Leases | FirstEnergy Lease Payments | Capital Trust[1] | Net |
|---|---|---|---|
| | (In millions) | | |
| 2014 | $250 | $48 | $202 |
| 2015 | 245 | 40 | 205 |
| 2016 | 213 | 13 | 200 |
| 2017 | 128 | 3 | 125 |
| 2018 | 126 | — | 126 |
| Years thereafter | 1,564 | — | 1,564 |

| | | | |
|---|---|---|---|
| Total minimum lease payments | $2,526 | $104 | $2,422 |

(1) PNBV purchased a portion of the lease obligation bonds associated with certain sale and leaseback transactions. These arrangements effectively reduce lease costs related to those transactions.

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| Operating Leases | FES |
|---|---|
| | (In millions) |
| 2014 | $143 |
| 2015 | 142 |
| 2016 | 130 |
| 2017 | 82 |
| 2018 | 101 |
| Years thereafter | 1,480 |
| Total minimum lease payments | $2,078 |

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy’s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2014 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

FirstEnergy had $3,404 million and $1,969 million of short-term borrowings as of December 31, 2013 and December 31, 2012, respectively. FirstEnergy’s available liquidity as of January 31, 2014, was as follows:

| Borrower(s) | Type | Maturity | Commitment | Available Liquidity |
|---|---|---|---|---|
| | | | (In millions) | |
| FirstEnergy[1] | Revolving | May 2018 | $2,500 | $224 |
| FES / AE Supply | Revolving | May 2018 | 2,500 | 2,489 |
| FET[2] | Revolving | May 2018 | 1,000 | — |
| | | Subtotal | $6,000 | $2,713 |
| | | Cash | — | 48 |
| | | Total | $6,000 | $2,761 |

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). The Facilities consist of a $2.5 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On October 31, 2013, FE amended its existing $2.5 billion multi-year syndicated revolving credit facility to exclude certain after-tax, non-cash write-downs and non-cash charges of approximately $1.4 billion (primarily related to Pension and OPEB mark-to-market adjustments, impairment of long-lived assets and regulatory charges) from the debt to total capitalization ratio calculations incurred through September 30, 2013. Additionally, the amendment provides for a future allowance of approximately $1.35 billion for after-tax, non-cash write-downs and non-cash charges over the remaining life of the facility. Similarly, the FES/AE Supply $2.5 billion revolving credit facility was also amended to exclude certain similar after-tax, non-cash write-downs and non-cash charges of $785.7 million incurred through September 30, 2013 from the debt to total capitalization ratio calculations. As of December 31, 2013, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its

subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.
During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

FE’s primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2013, FirstEnergy received $686 million of cash dividends and capital returned from its subsidiaries and paid $920 million in cash dividends to common shareholders. In January 2014, FirstEnergy’s Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2014, to shareholders of record at the close of business on February 7, 2014. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008.
Nuclear Operating Licenses

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft Generic Environmental Impact Statement and published a proposed rule on this subject in September of 2013. Other contentions proposed by the petitioners in this proceeding have been rejected by the ASLB. On February 18, 2014, Beyond Nuclear and Don't Waste Michigan, two of the petitioners in the Davis-Besse license renewal proceeding, requested that the NRC institute a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On February 27, 2014, these petitioners requested a suspension of the licensing decision in the Davis-Besse license renewal proceeding to allow the NRC to complete this rulemaking.

The following table summarizes the current operating license expiration dates for FES' nuclear facilities in service.

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

Nuclear Regulation

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2013, FirstEnergy had approximately $2.2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. FE maintains a $125 million parental guaranty relating to a potential shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. FE also maintains an $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate.

On October 4, 2013, during a refueling outage for Beaver Valley Unit 1, FENOC conducted a planned visual examination of the interior containment liner and coatings. The containment design for Beaver Valley includes an interior steel liner that is surrounded by reinforced concrete. A penetration through the containment steel liner plate of approximately 0.4 inches by 0.28 inches was discovered. A detailed investigation was initiated, including laboratory analysis that has indicated that the degraded area was initiated by foreign material inadvertently left in the concrete during construction. An assessment has been performed which concluded that any postulated leakage through the affected area was within overall allowable limits for the containment building. The structural integrity of the containment building is not affected. Repair of the containment liner was completed and Unit 1 was returned to service on November 4, 2013.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirm that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On February 1, 2014, the Davis-Besse Nuclear Power Station entered into an outage to install two new steam generators, replace about a third of the unit's 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall will be repaired during this outage to conform to its original design configuration. This condition is not expected to extend the outage.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (OE-$44 million, NG-$442 million, and TE-$23 million) per incident but not more than $76 million (OE-$7 million, NG-$66 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $2 billion (OE-$168 million, NG-$1.7 billion, TE-$90 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $14 million (OE-$1.2 million, NG-$12 million and TE-$0.6 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $79 million (OE-$7 million, NG-$68 million, TE-$3 million and ME-$1 million).

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

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

Environmental Matters

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

CAA Compliance

FirstEnergy is required to meet federally-approved $SO_2$ and NOx emissions regulations under the CAA. FirstEnergy complies with $SO_2$ and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which affirmed the dismissal on August 21, 2013 and then denied petitions for rehearing on December 12, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, and the Allegheny Utilities finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and $SO_2$ emissions in two phases (2009/2010 and 2015), ultimately capping $SO_2$ emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but 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 decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and $SO_2$ emissions in two phases (2012 and 2014), ultimately capping $SO_2$ emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and $SO_2$ emission allowances between power plants located in the same state and interstate trading of NOx and $SO_2$ emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the D.C. Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR and heard oral argument on December 10, 2013. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS has been challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. Oral arguments were heard on December 10, 2013. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payments of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including the EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of $CO_2$ equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard of 1,000 lbs. $CO_2$/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. $CO_2$/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. $CO_2$/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including $CO_2$, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting $CO_2$ emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The $CO_2$ emissions per KWH of electricity generated by FirstEnergy is lower than many of its 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 CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. The period for finalizing the Section 316(b) regulation was extended to April 17, 2014 under a Settlement Agreement between EPA and certain NGOs. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its asset retirement obligation for LBR by $163 million in 2013. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2013 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $128 million have been accrued through December 31, 2013. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

Fuel Supply

FirstEnergy currently has long-term coal contracts with various terms to acquire approximately 27.8 million tons of coal for the year 2014 which is approximately 100% of its estimated 2014 coal requirements. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, West Virginia, Montana and Wyoming. The contracts expire at various times through December 31, 2030. See “Environmental Matters" for factors pertaining to meeting environmental regulations affecting coal-fired generating units.

FirstEnergy has contracts for all uranium requirements through 2016 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2015 and partially fill requirements through 2024. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2020. A portion of enrichment requirements is also contracted for through 2024. Fabrication services for fuel assemblies are contracted for both Beaver Valley units through 2020 and Davis-Besse through 2025 and through the current operating license period for Perry. In addition to the existing commitments, FirstEnergy intends to make additional arrangements for the supply of uranium and for the subsequent conversion, enrichment, fabrication, and waste disposal services.

On-site spent fuel storage facilities are currently adequate for all FENOC operating units. Plant modifications are underway at Beaver Valley to establish a dry cask storage facility that, once completed, will extend spent fuel storage capacity through the end of current operating licenses at Beaver Valley Unit 1 (2036) and Beaver Valley Unity 2 (2047). Davis-Besse is planning to resume dry cask storage operations in 2017 which will extend on-site spent fuel storage capacity through 2037 (end of current operating license plus a 20-year operating license extension). Perry completed plant modification for dry cask storage in 2012 and has planned to conduct dry cask storage loading campaigns that will provide for sufficient spent fuel storage capacity through 2046 (end of current operating license plus a 20-year operating license extension).

The Federal Nuclear Waste Policy Act of 1982 provided for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. NG has contracts with the DOE for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. Yucca Mountain was approved in 2002 as a repository for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. Recent administrative and federal court proceedings render the completion of Yucca Mountain uncertain. The current Administration has stated the Yucca Mountain repository will not be completed. In light of this uncertainty, FirstEnergy intends to make additional arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

In November, 2013, the DOE was ordered by the U.S. Court of Appeals for the D.C. Circuit to submit a proposal to Congress to eliminate the ongoing 1 mill per KWH fee utilities pay for nuclear waste disposal. The ruling was based upon the DOE's failure to establish a court ordered assessment to validate the appropriateness of the fee in the wake of the cancellation of the Yucca Mountain repository. On January 3, 2014, DOE made the ordered submission to Congress. On that same day the government also filed a motion with the court for reconsideration en banc. If no legislative or further judicial action is taken to allow for continued collection of these fees under the Nuclear Waste Policy Act of 1982, they may be terminated.

Fuel oil and natural gas are used primarily to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so. Requirements are expected to average approximately 5 million gallons per year over the next five years. Natural gas demand at the combined cycle and peaking units is forecasted at approximately 27 million mcf in 2014.

System Demand

The 2013 maximum hourly demand for each of the Utilities was:

- OE—5,743 MW on July 18, 2013;
- Penn—944 MW on July 18, 2013;
- CEI—4,286 MW on July 18, 2013;
- TE—2,168 MW on July 18, 2013;
- JCP&L—6,353 MW on July 18, 2013;
- ME—3,009 MW on July 18, 2013;
- PN—3,039 MW on July 18, 2013;
- MP—1,943 MW on July 18, 2013;
- PE—2,820 MW on July 18, 2013; and
- WP—3,914 MW on July 18, 2013.

Supply Plan

Regulated Commodity Sourcing

Certain of the Utilities have default service obligations to provide power to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L’s default service or BGS supply is secured through a statewide competitive procurement process approved by the NJBPU. Default service for the Ohio Companies, Pennsylvania Companies and PE's Maryland jurisdiction are provided through a competitive procurement process approved by the PUCO (under the ESP), PPUC (under the DSP) and MDPSC (under the SOS), respectively. If any supplier fails to deliver power to any one of those Utilities’ service areas, the Utility serving that area may need to procure the required power in the market in their role as a LSE. West Virginia electric generation continues to be regulated by the WVPSC.

Unregulated Commodity Sourcing

The Competitive Energy Services segment, through FES and AE Supply, 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 and AE Supply provide the power requirements of their competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

FES and AE Supply have retail and wholesale competitive load-serving obligations in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey, serving both affiliated and non-affiliated companies. FES and AE Supply provide energy products and services to customers under various POLR, shopping, competitive-bid and non-affiliated contractual obligations. Geographically, most of FES' and AE Supply's obligations are in the PJM market area where all of their respective generation facilities are located.

Regional Reliability

All of FirstEnergy's facilities are located within PJM and operate under the reliability oversight of a regional entity known as RFC. This regional entity operates under the oversight of the NERC in accordance with a Delegation Agreement approved by FERC. RFC began operations under the NERC on January 1, 2006. On July 20, 2006, the NERC was certified by FERC as the ERO in the United States pursuant to Section 215 of the FPA and RFC was certified as a regional entity.

Competition

As a result of actions taken by state legislative bodies over the past several years, major changes in the electric utility business have occurred in portions of the United States, including Ohio, New Jersey, Pennsylvania and Maryland, where most of FirstEnergy utility subsidiaries operate. These changes have altered the way traditional integrated utilities conduct their business. FirstEnergy has aligned its business units to participate in the competitive electricity marketplace (see Management's Discussion and Analysis for more information regarding FirstEnergy's Competitive Energy Services segment).

FirstEnergy's Competitive Energy Services segment participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, New Jersey and Illinois, through FES and AE Supply. In these markets, the Competitive Energy Services segment competes: (1) to provide retail generation service directly to end users; (2) to provide wholesale generation service to utilities, municipalities and co-operatives, which, in turn, resell to end users; and (3) in the wholesale market.

Seasonality

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

Research and Development

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

FirstEnergy participates in other initiatives with industry R&D consortiums and universities to address technology needs for its various business units. Participation in these consortiums helps the company address research needs in areas such as plant operations and maintenance, major component reliability, environmental controls, advanced energy technologies, and transmission and distribution system infrastructure to improve performance, and develop new technologies for advanced energy and grid applications.

Executive Officers as of February 24, 2014

| Name | Age | Positions Held During Past Five Years | Dates |
|---|---|---|---|
| A. J. Alexander | 62 | President and Chief Executive Officer (A)(B) | *-present |
| | | Chief Executive Officer (F) | *-present |
| | | President and Chief Executive Officer (G) | 2011-present |
| L. M. Cavalier | 62 | Senior Vice President, Human Resources (B) | *-present |
| | | Senior Vice President, Human Resources (G) | 2011-present |
| M. J. Dowling | 49 | Senior Vice President, External Affairs (B)(G) | 2011-present |
| | | Vice President, External Affairs (B) | 2010-2011 |
| | | Vice President, Communications (B) | * - 2010 |
| B. L. Gaines | 60 | Senior Vice President, Corporate Services and Chief Information Officer (B)(G) | 2012-present |
| | | Vice President, Corporate Services and Chief Information Officer (B)(G) | 2011-2012 |
| | | Vice President, Shared Services, Administration and Chief Information Officer (B) | 2009-2011 |
| | | Vice President, Information Technology and Corporate Security and Chief Information Officer (B) | *-2009 |
| C. E. Jones | 58 | Executive Vice President & President, FirstEnergy Utilities (A)(B)(G) | 2014-present |
| | | Senior Vice President & President, FirstEnergy Utilities (G) | 2011-2013 |
| | | Senior Vice President & President, FirstEnergy Utilities (B) | 2010-2013 |
| | | President (I)(J) | 2011-present |
| | | President (C)(D) | 2010-present |
| | | Senior Vice President & President, FirstEnergy Utilities (A) | 2010-2011 |
| | | Senior Vice President, Energy Delivery & Customer Service (B) | 2009-2010 |
| | | Senior Vice President (C)(D) | 2009-2010 |
| | | President (E) | *-2009 |
| J. H. Lash | 63 | President, FE Generation (B)(G) | 2011-present |
| | | President (H)(K) | 2011-present |
| | | Chief Nuclear Officer (F) | 2011-2012 |
| | | President and Chief Nuclear Officer (F) | 2010-2011 |
| | | President, FirstEnergy Nuclear Operating Company (B) | 2010-2011 |
| | | Senior Vice President and Chief Operating Officer (F) | *-2010 |
| J. F. Pearson | 59 | Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K) | 2013-present |
| | | Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K) | 2012 |
| | | Vice President and Treasurer (A)(B)(C)(D)(E)(F)(K) | *-2012 |
| | | Vice President and Treasurer (G)(H)(I)(J) | 2011-2012 |
| D. R. Schneider | 52 | President (E) | 2009-present |
| | | Senior Vice President, Energy Delivery & Customer Service (B) | *-2009 |
| | | Senior Vice President (C)(D) | *-2009 |

| | | | |
|---|---|---|---|
| K. J. Taylor | 40 | Vice President, Controller and Chief Accounting Officer (A)(B)(G) | 2013-present |
| | | Vice President and Controller (C)(D)(E)(F)(H)(I)(J)(K) | 2013-present |
| | | Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K) | 2012-2013 |
| | | Assistant Controller (A)(B)(C)(D) | 2010-2012 |
| | | Assistant Controller (G)(I)(J) | 2011-2012 |
| | | Assistant Controller (E)(F)(H)(K) | 2012 |
| | | Manager, Financial Reporting & Technical Accounting (B) | 2009-2010 |
| L. L. Vespoli | 54 | Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K) | 2014-present |
| | | Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(K) | *-2013 |
| | | Executive Vice President and General Counsel (G)(H)(I)(J) | 2011-2013 |

| | | |
|---|---|---|
| * Indicates position held at least since January 1, 2009 | (E) Denotes executive officer of FES | (J) Denotes executive officer of TrAIL |
| (A) Denotes executive officer of FE | (F) Denotes executive officer of FENOC | (K) Denotes executive officer of FE Generation |
| (B) Denotes executive officer of FESC | (G) Denotes executive officer of AESC | |
| (C) Denotes executive officer of OE, CEI and TE | (H) Denotes executive officer of AGC | |
| (D) Denotes executive officer of ME, PN and Penn | (I) Denotes executive officer of MP, PE and WP | |

Employees

As of December 31, 2013, FirstEnergy’s subsidiaries had 15,754 employees located in the United States as follows:

| | Total Employees | Bargaining Unit Employees |
|---|---|---|
| FESC | 3,903 | 588 |
| OE | 1,131 | 717 |
| CEI | 848 | 568 |
| TE | 359 | 267 |
| Penn | 197 | 148 |
| JCP&L | 1,374 | 1,065 |
| ME | 640 | 487 |
| PN | 659 | 401 |
| ATSI | 37 | — |
| FES | 234 | — |
| FG | 2,130 | 1,299 |
| FENOC | 2,616 | 936 |
| MP | 519 | 320 |
| PE | 438 | 278 |
| WP | 669 | 422 |
| Total | 15,754 | 7,496 |

As of December 31, 2013, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 48% of FirstEnergy's total employees. There are various CBAs between FirstEnergy's subsidiaries and these unions, most of which have three year terms. There were seven CBAs covering approximately 2,850 bargaining unit employees that expired in 2013. Negotiations on five of the seven CBAs resulted in new CBAs that expire in 2014, 2015, or 2016.

FirstEnergy is engaged in separate negotiations with Local 102 and Local 180 of the UWUA. The CBA with Local 102, which represents approximately 700 employees at WP and PE, expired on April 30, 2013. WP and PE have work continuation plans in place in the event of any work stoppage. The CBA with Local 180, which represents approximately 150 employees at PN, expired on August 31, 2013. After multiple bargaining sessions without an agreement on a new CBA, FirstEnergy issued a final offer, which Local 180 rejected. Beginning November 25, 2013, FirstEnergy locked out members of Local 180 and commenced its work continuation plan.

In addition, two other CBAs due to expire in 2014 were extended to 2017 prior to their expiration.

FirstEnergy Web Site and Other Social Media Sites and Applications

Each of the registrants’ Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through the "Investors" page of FirstEnergy’s Internet web site at www.firstenergycorp.com.

These SEC filings are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post additional important information including press releases, investor presentations and notices of upcoming events, under the "Investors" section of FirstEnergy’s Internet web site and recognize FirstEnergy’s Internet web site as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under SEC Regulation FD.

Investors may be notified of postings to the web site by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet web site or through push alerts from FirstEnergy Investor Relations apps for Apple Inc.'s iPad® and iPhone® devices, which can be installed for free at the Apple® online store. FirstEnergy also uses Twitter® and Facebook® as an additional channel of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy’s Internet web site or its Twitter® or Facebook® site, and any corresponding applications of those sites, shall not be deemed incorporated into, or to be part of, this report.

## ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. Management of each Registrant regularly evaluates the most significant risks of the Registrants' businesses and reviews those risks with the FirstEnergy Board of Directors or appropriate Committees of the Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we currently consider material. Additional information on risk factors is included in “Item 1. Business” and “Item 7. Management’s Discussion and Analysis of Registrant and Subsidiaries” and in other sections of this Form 10-K that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results.

### Risks Related to Business Operations

We Have Taken a Series of Actions to Reposition our Asset Mix to Reflect a More Regulated Business Profile Focusing on Growing Our Regulated Distribution and Regulated Transmission Operations and Earnings. Whether This Repositioning Will Deliver the Desired Result is Subject to Certain Risks Which Could Adversely Affect Profitability and our Financial Condition in the Future

As a result of continuing weak economic conditions and depressed energy prices across our multi-state business territory, we have implemented a strategy to capitalize on growth opportunities available to our regulated operations - particularly in transmission. This strategy will involve continuing to reposition our asset mix over the next several years to reflect a more regulated business profile, and to target more than 80% of our earnings from our Regulated Distribution and Regulated Transmission segments. In connection with this repositioning, we intend to initiate distribution rate cases for certain of our distribution utility subsidiaries and grow our regulated transmission business, focusing first on ATSI, which has a formula rate recovery mechanism, but also extending throughout our service area. Our transmission expansion plan is designed to improve operating flexibility, increase reliability, position transmission capacity for future load growth and facilitate response to system events.

The success of our repositioning strategy will depend, in part, on successful recovery of our transmission investments. Factors that may affect rate recovery of our transmission investments may include: (1) whether the investments are included in PJM's regional transmission expansion plan; (2) FERC's evolving policies with respect to incentive rates for transmission assets; (3) FERC's consideration of the objections of those who oppose such investments and their recovery; and (4) timely development, construction, and operation of the new facilities. See "The Business Operations of Our Regulated Transmission Segment and Certain Activities of Our Competitive Energy Services Segment Are Subject to Regulation by FERC and Could be Adversely Affected by Such Regulation" below.

The success of this repositioning strategy will also depend, in part, on our achieving positive outcomes in distribution rate cases we have filed or will file. Adverse regulatory outcomes in the distribution rate cases (denial of cost recovery and/or imposition of conditions that create operational risk) and/or regulatory delays could have a material adverse effect on our regulatory strategy. See “State Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in, Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition” below.

Our repositioning strategy also could be impacted by our ability to finance the proposed expansion projects while maintaining adequate liquidity. There can be no assurance that the repositioning of our business to focus on our Regulated Distribution and Regulated Transmission segments will deliver the desired result which could adversely affect our profitability and financial condition.

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

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

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operation and maintenance costs, purchased power costs and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses or may require us to incur significant costs as a result of operating our higher cost units or obtaining replacement power from third parties in the open market to satisfy our sales obligations. Moreover, if we were unable to perform under contractual obligations, including, but not limited to, our coal and coal transportation contracts, penalties or liability for damages could result.

FES, FG and the Ohio Companies are exposed to losses under their applicable sale-leaseback arrangements for generating facilities upon the occurrence of certain contingent events that could render those facilities worthless. Although we believe these types of events are unlikely to occur, FES, FG and the Ohio Companies have a maximum exposure to loss under those provisions of approximately $1.274 billion for FES and $485 million for OE and an aggregate of $267 million for TE and CEI as co-lessees.

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

Changes in Commodity Prices Including, but Not Limited to Natural Gas, Could Adversely Affect Our Profit Margins

We purchase and sell electricity in the competitive retail and wholesale markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) can affect our profit margins. Competition and changes in the short or long-term market price of electricity, which are affected by changes in other commodity costs and other factors, may impact our results of operations and financial position by decreasing sales margins or increasing the amount we pay to purchase power to satisfy our sales obligations in the states we do business. We are exposed to risk from the volatility of the market price of natural gas. Our ability to sell at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants. The availability of natural gas and issues related to its accessibility may have a long-term material impact on the price of natural gas. In addition, the global economy could lead to lower international demand for coal, oil and natural gas, which may lower fossil fuel prices and put downward pressure on electricity prices.

Electricity and fuel prices may fluctuate substantially for a variety of reasons, including:

- changing weather conditions or seasonality;
- changes in electricity usage by our customers caused in part by energy and efficiency mandates and demand response initiatives;
- illiquidity and credit worthiness of participants in wholesale power and other markets;
- transmission congestion or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy commodities, including but not limited to, coal, natural gas and oil;
- changes in power production capacity;
- outages, deactivations and retirements at our power production facilities or those of our competitors;
- changes in production and storage levels of natural gas, such as that which could result from the natural gas produced in the Marcellus and Utica regions, lignite, coal, crude oil and refined products resulting in over or under supply;
- changes in legislation and regulation; and
- natural disasters, wars, acts of sabotage, terrorist acts, embargoes and other catastrophic events.

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

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

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

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

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

Financial Derivatives Reforms Could Increase Our Liquidity Needs and Collateral Costs and Impose Additional Regulatory Burdens

The Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law in July 2010 with the primary objective of increasing oversight of the United States financial system including the regulation of most financial transactions, swaps and derivatives. Dodd-Frank requires CFTC and SEC rulemaking to implement its provisions. Although the CFTC and the SEC have completed some of their rulemaking, a significant amount of rulemaking remains.

We rely on the OTC derivative markets as part of our program to hedge the price risk associated with our power portfolio. The effect on our operations of this legislation will depend in part on whether we are determined to be a swap dealer, a major swap participant or a qualifying end-user through a self-identification process. The overall impact of those regulations may be reduced but not eliminated for companies that participate in the swap market as "end-users" for hedging purposes. If we are determined to be a swap dealer or a major swap participant, we will be required to commit substantial additional capital toward collateral costs to meet the margin requirements of the major exchanges, comply with increased reporting and record-keeping requirements and follow CFTC-specified business conduct standards.

Even if we are not determined to be a swap dealer or a major swap participant, as an end-user, we are required to comply with additional regulatory obligations under Dodd-Frank, which includes record-keeping, reporting requirements and the clearing of some transactions that we would otherwise enter into over-the-counter. Also, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swap market to decrease. The new rules could impede our ability to meet our hedge targets in a cost-effective manner. FirstEnergy cannot predict the ultimate impact Dodd-Frank rulemaking will have on its results of operations, cash flows or financial position.

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

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

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

We also face credit risks from parties with whom we contract who could default in their performance. See "The Stability of Counterparties Could Adversely Affect Us" below.

Nuclear Generation Involves Risks that Include Uncertainties Relating to Health and Safety, Additional Capital Costs, the Adequacy of Insurance Coverage and Nuclear Plant Decommissioning, Which Could Have a Material Adverse Effect on Our Business, Results of Operations and Financial Condition

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

- the potential harmful effects on the environment and human health, including loss of life, resulting from unplanned radiological releases associated with the operation of our nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations, including any incidents of unplanned radiological release, or those of others in the United States;
- uncertainties with respect to contingencies and assessments if insurance coverage is inadequate; and
- uncertainties with respect to the technological and financial aspects of spent fuel storage and decommissioning nuclear plants, including but not limited to, waste disposal at the end of their licensed operation and increases in minimum funding requirements or costs of completion.

The NRC has broad authority under federal law to impose licensing security and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a unit, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants, including ours. Also, a serious nuclear incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit. See "Potential NRC Regulation in Response to the Incident at Japan's Fukushima Daiichi Nuclear Plant Could Adversely Affect Our Business and Financial Condition" below and Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to Consolidated Financial Statements. Any one of these risks relating to our nuclear generation could have a material adverse effect on our business, results of operations and financial condition.

The Outcome of Litigation, Arbitration, Mediation, and Similar Proceedings, Involving Our Business, or That of One or More of Our Operating Subsidiaries, is Unpredictable and an Adverse Decision in Any Material Proceeding Could Have a Material Adverse Effect on Our Financial Position and Results of Operations.

We are involved in a number of litigation, arbitration, mediation, and similar proceedings including, but not limited to, such proceedings relating to our fuel and fuel transportation contracts. These matters may divert financial and management resources that would otherwise be used to benefit our operations. No assurances can be given that the results of these matters will be favorable to us. An adverse resolution of any of these material matters could have a material adverse impact on our financial position and results of operations. In addition, we are sometimes subject to investigations and inquiries by various state and federal regulators due to the heavily regulated nature of our industry. Any material inquiry or investigation could potentially result in an adverse ruling against us, which could have a material adverse impact on our financial position and operating results.

We Have a Significant Percentage of Coal-Fired Generation Capacity Which Exposes Us to Risk from Regulations Relating to Coal and Coal Combustion Residuals

Approximately 55% of FirstEnergy's generation fleet capacity is coal-fired. Historically, coal-fired generating plants have greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to emissions of $SO_2$ and NOx than other types of generation facilities. The MATS established coal-fired emission standards for mercury, PM and HCL, effective in April 2015. In addition, the EPA has proposed regulations that include an option to reclassify coal combustion residuals as a "special" hazardous waste. There are also a number of federal, state and international initiatives under consideration to, among other things, require reductions in GHG emissions, including a September 20, 2013, EPA proposed new source performance standard that would require partial carbon capture and storage for newly constructed coal-fired generating plants. On June 25, 2013, a Presidential Memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. These legal requirements and initiatives could impose substantial additional costs, extensive mitigation efforts and, in the case of GHG requirements, could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements.

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

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our nuclear generation facilities and under pension and other postemployment benefit plans. Certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission nuclear generating stations, to pay future pensions and other obligations, requires significant judgment and actual results may differ significantly from current estimates.

Capital market conditions that generate investment losses or increase the present value of liabilities can negatively impact our results of operations and financial position.

We Could be Subject to Higher Costs and/or Penalties Related to Mandatory Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets

Owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by the NERC and approved by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. NERC, RFC and FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. FERC has authority to impose penalties up to and including $1.0 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by FERC, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs. Although these entities are themselves ultimately regulated by FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the perceived potential for exercise of market power and to ensure the market functions. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity. In addition, PJM may direct our transmission-owning affiliates to build new transmission facilities to meet PJM's reliability requirements or to provide new or expanded transmission service under the PJM open access transmission tariff.

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

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

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

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

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

We purchase fuel from a number of suppliers. The lack of availability of fuel at expected prices, or a disruption in the delivery of fuel which exceeds the duration of our on-site fuel inventories, including disruptions as a result of weather, increased transportation costs or other difficulties, labor relations or environmental or other regulations affecting our fuel suppliers, could cause an adverse impact on our ability to operate our facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect our results of operations. Operation of our coal-fired generation facilities is highly dependent on our ability to procure coal. We have long-term contracts in place for a majority of our coal and coal transportation needs, some of which run through 2032 and certain of which relate to deactivated plants. We have asserted force majeure defenses for delivery shortfalls under certain agreements and we are in discussions with the applicable counterparties. We can provide no assurance that these agreements will be favorably resolved with respect to certain unresolved aspects of the agreements. If we fail to reach a resolution with applicable counterparties and if it were ultimately determined that, contrary to our belief, the force majeure provision or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. In addition, we may from time to time enter into new, or renegotiate certain of these contracts, but can provide no assurance that such contracts will be negotiated or renegotiated, as the case may be, on satisfactory terms, or at all. In addition, if prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

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

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

Customer demand could change as a result of severe weather conditions or other circumstances over which we have no control. We satisfy our electricity supply obligations through a portfolio approach of providing electricity from our generation assets, contractual relationships and market purchases. A significant increase in demand could adversely affect our energy margins if we are required to provide the energy supply to fulfill this increased demand at fixed rates, which we expect would remain below the wholesale prices at which we would have to purchase the additional supply if needed or, if we had available capacity, the prices at which we could otherwise sell the additional supply. A significant decrease in demand, resulting from factors including but not limited to increased customer shopping, more stringent energy efficiency mandates and increased demand response initiatives could cause a decrease in the market price of power. Accordingly, any significant change in demand could have a material adverse effect on our results of operations and financial position.

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

Our business follows economic cycles. Economic conditions are a determinant of the demand for electricity and declines in the demand for electricity will reduce our revenues. The regional economy in which our Utilities operate is influenced by conditions in industries in our business territories, e.g. shale gas, automotive, chemical, steel and other heavy industries, and as these conditions change, our revenues will be impacted. Additionally, the primary market areas of our Competitive Energy Services segment overlap, to a large degree, with our Utilities' territories and hence its revenues are substantially impacted by the same economic conditions.

Increases in Economic Uncertainty May Lead to a Greater Amount of Uncollectible Customer Accounts

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

We May Recognize Impairments of Recorded Goodwill or of Some of Our Long-Lived Assets, Which Would Result in Write-Offs of the Impaired Amounts and Could Have an Adverse Effect on Our Results of Operations

Goodwill could become impaired at one or more of our reportable segments. In addition, one or more of our long-lived assets could become impaired. The actual timing and amounts of any impairments in future years would depend on many factors, including interest rates, sector market performance, our capital structure, natural gas or other commodity prices, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable acquisitions, environmental regulations and other factors.

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

We must find ways to balance the retention of our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Further, a significant number of our physical workforce are represented by unions and while we believe that our relations with our employees are generally fair, we cannot provide assurances that the company will be completely free of labor disruptions such as work stoppages, work slowdowns, union organizing campaigns, strikes, lockouts or that any existing labor disruption will be favorably resolved. Mitigating these risks could require additional financial commitments and the failure to retain or attract trained and qualified labor could have an adverse effect on our business.

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

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

Our Results May be Adversely Affected by the Volatility in Pension and OPEB Expenses.

FirstEnergy recognizes in income the change in the fair value of plan assets and net actuarial gains and losses for its defined Pension and OPEB plans. This adjustment is recognized in the fourth quarter of each year and whenever a plan is determined to qualify for a remeasurement, which could result in greater volatility in pension and OPEB expenses and may materially impact our results of operations under GAAP.

Security Breaches, Including Cybersecurity Breaches, and Other Disruptions Could Compromise Our Business Operations and Critical and Proprietary Information and Expose Us to Liability, Which Could Adversely Affect our Business, Financial Condition and Reputation

In the ordinary course of our business, we store sensitive data, intellectual property and proprietary information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks. Additionally, we use and are dependent upon information technology systems that utilize sophisticated operational systems and network infrastructure to run all facets of our generation, transmission and distribution services. The secure maintenance of information and information technology systems is critical to our operations. Despite security measures we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to attacks by hackers or terrorists as a result of the rise in the sophistication and volume of cyber attacks. Also, our information and information technology systems may be breached due to viruses, human error, malfeasance or other malfunctions and disruptions. Any such attack or breach could: (i) compromise our generation, transmission and distribution services, development and construction of new facilities or capital improvement projects; (ii) adversely affect our customer operations; (iii) corrupt data; or (iv) result in unauthorized access to the information stored on our networks, including personal customer data, causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in harmful effects on the environment and human health, including loss of life.. Although FirstEnergy carries property and casualty insurance that may mitigate the potential impact of a cyber incident, any such attack, breach, access, disclosure or other loss of information could result in lost revenue, the inability to conduct critical business functions and serve customers, legal claims or proceedings, regulatory penalties, increased regulation, increased protection costs for enhanced cyber security systems or personnel, damage to our reputation and/or the rendering of our disclosure controls and procedures ineffective, all of which could adversely affect our business and financial condition.

Physical Acts of War, Terrorism or Other Attacks on any of Our Facilities or Other Infrastructure Could Have an Adverse Effect on Our Business, Results of Operations and Financial Condition

As a result of the continued threat of physical acts of war, terrorism, or other attacks in the United States, our electric generation, fuel storage, transmission and distribution facilities and other infrastructure, including nuclear and other power plants, transformer and high voltage lines and substations, or the facilities or other infrastructure of an interconnected company, could be direct targets of, or indirect casualties of, an act of war, terrorism, or a cyber or other attack, which could result in disruption of our ability to generate, purchase, transmit or distribute electricity, otherwise disrupt our customer operations and/or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Any such disruption or incident could result in a significant decrease in revenue, significant additional capital and operating costs, including additional costs to implement additional security systems or personnel to purchase electricity and to replace or repair our assets over and above any available insurance reimbursement, higher insurance deductibles, higher premiums and more restrictive insurance policies, generally, and significant damage to our reputation, which could have an adverse effect on our business, results of operations and financial condition.

Capital Improvements and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters or Could be Canceled Which Could Adversely Affect Our Business and Results of Operations

Our business plan calls for extensive capital investments in electric generation, transmission and distribution, including but not limited to our recently announced transmission expansion program. We may be exposed to the risk of substantial price increases in the costs of labor and materials used in construction, nonperformance of equipment and increased costs due to delays, including delays relating to the procurement of permits or approvals, adverse weather or environmental matters. We engage numerous contractors and enter into a large number of construction agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors’ inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. Also, because we enter into construction agreements for the necessary materials and to obtain the required construction related services, any cancellation by FirstEnergy of a construction agreement could result in significant termination payments or penalties. Any delays, increased costs or losses or cancellation of a construction project could adversely affect our business and results of operations, particularly if we are not permitted to recover any such costs in rates.

Changes in Technology and Regulatory Policies May Significantly Affect Our Generation Business by Making Our Generating Facilities Less Competitive

We primarily generate electricity at large central facilities. This method results in economies of scale and lower unit costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies will reduce costs of new technology and/or changes in regulatory policy will create benefits that make these new technologies more competitive with central station electricity production. Such advances in technologies and/or changes in regulatory policy could decrease sales and revenues from our existing generation assets, and this could have a material adverse effect on our results of operations. To the extent that new generation technologies are connected directly to load, bypassing the transmission and distribution systems, potential impacts could include decreased transmission and distribution revenues, stranded assets and increased uncertainty in load forecasting and integrated resource planning.

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

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

Certain FirstEnergy Companies May Not be Able to Meet Their Obligations to or on behalf of Other FirstEnergy Companies or their Affiliates

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies because of transactions involving energy, coal, other commodities, services and hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, resulting in the nondefaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Our hedging activities are generally undertaken with a view to overall FirstEnergy exposures. Some FirstEnergy companies may therefore be more or less hedged than if they were to engage in such transactions alone. Also, some companies affiliated with FirstEnergy also provide guarantees to third party creditors on behalf of other FirstEnergy affiliates under transactions of the type described above or under financing transactions. Any failure to perform under such a guarantee by the affiliated FirstEnergy guarantor company or under the underlying transaction by the FirstEnergy company on whose behalf the guarantee was issued could have similar adverse impacts on one or both FirstEnergy companies or their affiliates.

Certain FirstEnergy Companies Have Guaranteed the Performance of Third Parties, Which May Result in Substantial Costs in the Event of Non-Performance

Certain FirstEnergy Companies have issued certain guarantees of the performance of others, which obligates such FirstEnergy Companies to perform in the event that the third parties do not perform. FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million in connection with the repayment of a prior term loan facility under which Signal Peak and Global Rail were borrowers. In the event of non-performance by the third parties, FirstEnergy could incur substantial cost to fulfill the obligations under such guarantees. Such performance guarantees could have a material adverse impact on our financial position and operating results.

Energy Companies are Subject to Adverse Publicity Which Make Them Vulnerable to Negative Regulatory and Legislative Outcomes

Energy companies, including FirstEnergy's utility subsidiaries, have been the subject of criticism focused on the reliability of their distribution services and the speed with which they are able to respond to power outages, such as those caused by storm damage. Adverse publicity of this nature, or adverse publicity associated with our nuclear and/or coal-fired facilities may cause less favorable legislative and regulatory outcomes and damage our reputation, which could have an adverse impact on our business.

Risks Associated With Regulation

To the Extent Our Policies to Control Costs Designed to Mitigate Low Energy, Capacity and Market Prices are Unsuccessful, We Could Experience a Negative Impact on Our Results of Operations and Financial Condition

The May 2013 PJM RPM auction for 2016/2017 capacity produced prices in the region served by our competitive generation segment that were lower than expected. This result may be a broader indication of an underlying supply/demand imbalance that continues to affect power producers in this region, adding pressure on already depressed energy prices and potentially pushing any significant power price recovery further into the future than we, or the industry at large, previously expected. As we experience these trends, as part of our ongoing comprehensive review of competitive operations related to, among other things, plant economics, since 2012 we have deactivated more than 5,000 MW of competitive generation. To the extent our policies designed to control our costs, or other facets of our financial plan, are unsuccessful, we could experience a negative impact on our results of operations and financial condition.

Complex and Changing Government Regulations, Including Those Associated With Rates and Pending Rate Cases Could Have a Negative Impact on Our Results of Operations

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

Our transmission and operating utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may be decreased as a result of actions taken by the FERC or by one or more of the state regulatory commissions in which our utility subsidiaries operate. Also, these rates may not be set to recover the Utility's expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered. For example, we may be unable to timely recover the costs for our energy efficiency investments, expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. While rate regulation is premised on providing an opportunity to earn a reasonable return on invested capital and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner. Further, there can be no assurance that we will retain the expected recovery in future rate cases.

State Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in, Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition.

Each of the Utilities' retail rates is set by its respective regulatory agency for utilities in the state in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC through traditional, cost-based regulated utility ratemaking. As a result, any of the Utilities may not be permitted to recover its costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Factors that may affect outcomes in the distribution rate cases include: (i) the value of plant in service; (ii) authorized rate of return; (iii) capital structure (including hypothetical capital structures); (iv) depreciation rates; (v) the allocation of shared costs, including consolidated tax, across the FirstEnergy utilities; (vi) regulatory approval of rate recovery mechanisms for capital spending programs (including for example accelerated deployment of smart meters); and (vii) the accuracy of forecasts used for ratemaking purposes in "future test year" cases. FirstEnergy can provide no assurance that any base rate request filed by any of the Utilities, including the pending JCP&L base rate case and the anticipated WVPSC base rate case, will be granted in whole or in part, or as to when it will receive a decision on such requests. Any denial of, or delay in, any base rate request could restrict the applicable Utility from fully recovering its costs of service, may impose risks on its operations, and may negatively impact its results of operations and financial condition. In addition, to the extent that any of the Utilities seeks rate increases after an extended period of frozen or capped rates, pressure may be exerted on the applicable legislators and regulators to take steps to control rate increases, including through some form of rate increase moderation, reduction or freeze. Any related public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues that are ultimately obtained, and the ability of the Utility to recover costs. Such uncertainty may restrict operational flexibility and resources, and reduce liquidity and increase financing costs.

Any Denial of, or Delay in, Cost Recovery Resulting from JCP&L's Pending Base Rate Case or in Association with the Generic Storm Proceeding Before the NJBPU May Impose Risks on our Operations and May Negatively Impact our Credit Rating, Results of Operations and Financial Condition

Our distribution rates in New Jersey are set by the NJBPU through traditional, cost-based regulated utility ratemaking. As a result, JCP&L may not be able to recover all of its increased, unexpected or necessary costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Pursuant to the written Order of the NJBPU dated July 31, 2012, requiring JCP&L to file a base rate case to determine whether its rates are just and reasonable, JCP&L filed its base rate case petition on November 30, 2012. In a subsequent filing, JCP&L updated its petition to request recovery for the impact of Hurricane Sandy. However, the NJBPU in its written Order dated May 31, 2013, held that the 2011 major storm costs would be reviewed expeditiously in a generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed, and the 2012 major storm costs would be reviewed in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding.

We can provide no assurance that JCP&L's request to increase rates in its pending base rate case, or any future proceeding, will be granted in whole or in part, or when it will receive a decision on such requests from the NJBPU. Any denial of, or delay in, its request to increase rates in the pending base rate case or to recover costs associated with Hurricane Sandy and other 2011 or 2012 major storms could negatively impact our results of operations and financial condition. Any denial of, or delay in, the request to increase rates embodied in an Order from the NJBPU resulting from the base rate case could restrict it from fully recovering its costs of service, may impose risks on our operations, and may negatively impact our results of operations and financial condition. Also, the uncertainty regarding JCP&L's pending rate case and generic storm proceedings have already led to adverse credit rating agency action, and could lead to further adverse rating agency actions in the future.

The Conditions Imposed by the WVPSC on MP's Completion of its Generation Resource Transaction and the Pending Appeal of the Related WVPSC Approval Order Could Present Challenges for Our Business in the Future, Which Could Adversely Affect Our Ability to Realize Anticipated Benefits of that Transaction

The Generation Resource Transaction was completed on October 9, 2013, subject to certain conditions imposed by the WVPSC in its approval order issued on October 7, 2013. One of those conditions permits a return on, and return of, an acquisition adjustment only to the extent that 50% of the net margins from off-system transactions from the additional Harrison capacity acquired by MP will support that return requirement. MP's ability to satisfy this condition may depend on a variety of factors, including the future operating performance of the Harrison Power Station, commodity prices, general economic conditions and financial and business conditions, which may be subject, in part, to factors beyond MP's and FirstEnergy's control. Any of these factors could adversely affect MP's ability to satisfy this condition and could have an adverse effect on MP's and FirstEnergy's financial condition and results of operations.

In addition, on November 6, 2013, the WVCAG filed a petition with the Supreme Court of Appeals of West Virginia appealing the WVPSC's October 7, 2013 order approving the Generation Resource Transaction. MP and FirstEnergy intend to defend vigorously the approval order before the Court, but are unable to predict the effect of any unfavorable outcome that might result from this appeal, but such an outcome could have a material adverse effect on MP's and FirstEnergy's business, results of operations, cash flows and financial condition.

Regulatory Changes in the Electric Industry Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of regulatory initiatives, changes in the electric utility business have occurred, and are continuing to take place throughout the United States, including the states in which we do business. These changes have resulted, and are expected to continue to result, in fundamental alterations in the way utilities and competitive energy providers conduct their business. FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry. Similarly, the PUCO and PPUC have in recent years instituted investigations in Ohio and Pennsylvania, respectively, to evaluate the vitality of, and to make recommendations for improvements to, the competitive retail markets in those states.

If any regulatory efforts result in decreased margins or unrecoverable costs, our business and results of operations would be adversely affected. We cannot predict the extent or timing of further regulatory efforts to modify our business or the industry.

The Business Operations of Our Regulated Transmission Segment and Certain Activities of Our Competitive Energy Services Segment Are Subject to Regulation by FERC and Could be Adversely Affected by Such Regulation

FERC granted certain FirstEnergy generating subsidiaries authority to sell electricity at market-based rates. These orders also granted waivers of certain FERC accounting, record-keeping and reporting requirements, as well as, waivers of the requirements to obtain FERC approval for issuances of securities. FERC's orders that grant this market-based rate authority reserve to FERC the right to revoke or revise that authority if FERC subsequently determines that these companies can exercise market power in transmission or generation, or create barriers to entry, or have engaged in prohibited affiliate transactions. In the event that one or more of FirstEnergy's market-based rate authorizations were to be revoked or adversely revised, the affected FirstEnergy subsidiary(ies) would be required to file with FERC for authorization of individual wholesale sales transactions, which could involve costly and possibly lengthy regulatory proceedings. In addition, such subsidiary(ies) would no longer enjoy the flexibility afforded by the waivers associated with the current market-based rate authorizations. FERC policy currently permits recovery of prudently-incurred costs associated with the expansion and updating of transmission infrastructure within its jurisdiction. If FERC were to adopt a different policy regarding recovery of transmission costs or if transmission needs do not continue or develop as projected, our strategy of investing in transmission could be curtailed. If FERC were to lower the rate of return it has authorized for FirstEnergy's transmission investments and facilities, it could reduce future net income and cash flows and impact FirstEnergy’s financial condition.

There Are Uncertainties Relating to Our Participation in RTOs

RTO rules could affect our ability to sell power produced by our generating facilities to users in certain markets The rules governing the various regional power markets may change from time to time, which could affect our costs or revenues. In some cases these changes are contrary to our interests and adverse to our financial returns. The prices in day-ahead and real-time energy markets and RTO capacity markets have been volatile and RTO rules may contribute to this volatility.

All of our generating assets currently participate only in PJM, which conducts RPM auctions for capacity on an annual planning year basis. The prices our generating companies can charge for their capacity are determined by the results of the PJM auctions, which are impacted by the supply and demand of capacity resources and load within PJM and also may be impacted by transmission system constraints and PJM rules relating to bidding for demand response, energy efficiency resources, and imports, among others. Auction prices could fluctuate substantially over relatively short periods of time. We cannot predict the outcome of future auctions, but if the auction prices are sustained at low levels, our results of operations, financial condition and cash flows could be adversely impacted.

We incur fees and costs to participate in RTOs. Administrative costs imposed by RTOs, including the cost of administering energy markets, may increase. To the degree we incur significant additional fees and increased costs to participate in an RTO, and we are limited with respect to recovery of such costs from retail customers, we may suffer financial harm.

We may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. We may be required to expand our transmission system according to decisions made by an RTO rather than our own internal planning processes. Various proposals and proceedings currently taking place at the FERC may cause transmission rates to change from time to time. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on us.

As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO’s market and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.

Energy Efficiency and Peak Demand Reduction Mandates and Energy Price Increases Could Negatively Impact Our Financial Results

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption. Conservation programs could impact our financial results in different ways. To the extent conservation resulted in reduced energy demand or significantly slowed the growth in demand, the value of our competitive generation and other unregulated business activities could be adversely impacted. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery time frame in the states where we operate. In New Jersey, we recover the costs for energy efficiency programs through the SBC. Currently only our Ohio Companies recover lost revenues. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We could also be impacted if any future energy price increases result in a decrease in customer usage. Our results could be adversely affected if we are unable to increase our customer’s participation in our energy efficiency programs. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

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

As a result of a comprehensive review of FirstEnergy's coal-fired generating facilities in light of the MATS rules and other expanded environmental requirements, we deactivated twenty-one (21) older coal-fired generating units in 2012 and 2013, and intend to deactivate five (5) additional older coal-fired generating units when RMR requirements terminate. We may be forced to shut down other facilities or change their operating status, either temporarily or permanently, if we are unable to comply with these or other existing or new environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are uneconomical.

The EPA is Conducting NSR Investigations at a Number of Generating Plants that We Currently or Formerly Owned, the Results of Which Could Negatively Impact Our Results of Operations and Financial Condition

We may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations, including, for example, the applicability of EPA's NSR programs. Under the CAA, modification of our generation facilities in a manner that results in increased emissions could subject our existing generation facilities to the far more stringent new source standards applicable to new generation facilities.

The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work considered by the companies to be routine maintenance. We are currently involved in litigation and EPA investigations concerning alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position but we are unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition. For a more complete discussion see Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to Consolidated Financial Statements.

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

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for, among other things, installation and operation of pollution control equipment, emissions monitoring and fees, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. On December 21, 2011, the EPA finalized the MATS to establish emission standards for, among other things, mercury, PM and HCL, for electric generating units. The costs associated with MATS compliance, and other environmental laws, is substantial and contributed to the Company's decision to deactivate twenty-one (21) older coal-fired generating units in 2012 and 2013 and plans to deactivate five (5) additional coal-fired generating units when RMR requirements terminate. MATS is also being challenged by numerous entities, including FG, in the U.S. Court of Appeals for the D.C. Circuit. Depending on the outcome of these legal proceedings and how MATS and other EPA regulations are ultimately implemented, MP's, FG's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's operations may result.

Moreover, new environmental laws or regulations including, but not limited to MATS, or changes to existing environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Because of the deregulation of generation, we may not directly recover through rates additional costs incurred for such compliance. Our compliance strategy, including but not limited to, our assumptions regarding estimated compliance costs, although reasonably based on available information, may not successfully address future relevant standards and interpretations. If we fail to comply with environmental laws and regulations or new interpretations of longstanding requirements, even if caused by factors beyond our control, that failure could result in the assessment of civil or criminal liability and fines. In addition, any alleged violation of environmental laws and regulations may require us to expend significant resources to defend against any such alleged violations.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. Environmental advocacy groups, other organizations and some agencies in the United States and elsewhere are focusing considerable attention on $CO_2$ emissions from power generation facilities and their potential role in climate change. There is a growing consensus in the United States and globally that GHG emissions are a major cause of global warming and that some form of regulation will be forthcoming at the federal level with respect to GHG emissions (including $CO_2$) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances. As a result, it is possible that state and federal regulations will be developed that will impose more stringent limitations on emissions than are currently in effect. Due to the uncertainty of control technologies available to reduce GHG emissions, including $CO_2$, as well as the unknown nature of potential compliance obligations should climate change regulations be enacted, we cannot provide any assurance regarding the potential impacts these future regulations would have on our operations. In addition, any legal obligation that would require us to substantially reduce our emissions could require extensive mitigation efforts and, in the case of carbon dioxide legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. The impact that any new environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation may have on our results of operations, financial condition or liquidity is not determinable, but potential legislative or regulatory programs restricting $CO_2$ emissions, or litigation alleging damages from GHG emissions could require significant capital and other expenditures or result in changes to its operations.

See Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to Consolidated Financial Statements for a more detailed discussion of the above-referenced EPA regulations and the federal, state and international initiatives seeking to reduce GHG emissions.

We Could be Exposed to Private Rights of Action Seeking Damages Under Various State and Federal Law Theories

Claims have been made against certain energy companies alleging that $CO_2$ emissions from power generating facilities constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While FirstEnergy is not a party to this litigation, it, and/or one of its subsidiaries, could be named in actions making similar allegations. An unfavorable ruling in any such case could have an adverse impact on our results of operations and financial condition and could significantly impact our operations.

Various Federal and State Water Regulations May Require Us to Make Material Capital Expenditures

The EPA has proposed regulatory changes, specifically, eight treatment options for waste water discharge from electric power plants, of which four are "preferred" by the agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements and the EPA is scheduled to finalize these regulatory changes in May 2014. The EPA has also established performance standards under the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants, specifically, 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). In 2011, the EPA proposed new regulations under the CWA which generally require fish impingement to be reduced to a 12% annual average and calls for studies to be conducted at the majority of our existing generating facilities to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic life. FirstEnergy is studying the cost and effectiveness of various control options to divert fish away from its plants' cooling water intake systems. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states, the future costs of compliance with these standards may require material capital expenditures. See Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to Consolidated Financial Statements for a more detailed discussion of the various federal and state water quality regulations listed above.

Compliance with any Coal Combustion Residual Regulations Could Have an Adverse Impact on Our Results of Operations and Financial Condition

We are subject to various federal and state solid, non-hazardous and hazardous waste regulations. The EPA has requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

The EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry and has proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be issued could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on our results of operations and financial condition. See Note 16, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements.

Remediation of Environmental Contamination at Current or Formerly Owned Facilities

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

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

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

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

Availability and Cost of Emission Allowances Could Negatively Impact Our Costs of Operations

Although recent court rulings and current conditions have reduced the immediate risk of a negative impact on our operating costs, the uncertainty around CAA programs and requirements continue to be a major concern. We are still required to maintain, either by allocation or purchase, sufficient emission allowances to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet our obligations imposed by various applicable environmental laws. If our operational needs require more than our allocated allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances, or install costly new emission controls. As we use the emission allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, the purchase of such allowances could materially increase our costs of operations in the affected markets.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs

If federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation would not also provide for adequate cost recovery, it could result in significant changes in our business, including

REC purchase costs, purchased power and capital expenditures. Any such changes may have an adverse effect on our financial condition or results of operations.

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

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

Potential NRC Regulation in Response to the Incident at Japan's Fukushima Daiichi Nuclear Plant Could Adversely Affect Our Business and Financial Condition

As a result of the NRC's investigation of the incident at the Fukushima Daiichi nuclear plant, the NRC has begun to promulgate new or revised requirements with respect to nuclear plants located in the United States, which could necessitate additional expenditures at our nuclear plants. For example, as a follow up to the NRC near-term Task Force's review and analysis of the Fukushima Daiichi accident, in January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the task force. The NRC has also issued orders and guidance that increases procedural and testing requirements, requires physical modifications to our plants and is expected to increase future compliance and operating costs. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. It is also possible that the NRC could suspend or otherwise delay pending nuclear relicensing proceedings, including the Davis-Besse relicensing proceeding. The impact of any such regulatory actions could adversely affect FirstEnergy's financial condition or results of operations.

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

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

Future Changes in Accounting Standards May Affect Our Reported Financial Results

The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially impact how we report our financial condition and results of operations. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial position.

Changes in Local, State or Federal Tax Laws Applicable To Us or Adverse Audit Results or Tax Rulings, and Any Resulting Increases in Taxes and Fees, May Adversely Affect Our Results of Operation, Financial Audit and Cash Flow

FirstEnergy is subject to various local, state and federal taxes, including income, franchise, real estate, sales and use and employment-related taxes. We exercise significant judgment in calculating such tax obligations, booking reserves as necessary to reflect potential adverse outcomes regarding tax positions we have taken and utilizing tax benefits, such as carryforwards and credits. Additionally, various tax rate and fee increases may be proposed or considered in connection with such changes in local, state or federal tax law. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, or whether any such legislation or regulation will be passed by legislatures or regulatory bodies. Any such changes, or any adverse tax audit results or adverse tax rulings on positions taken by FirstEnergy or its subsidiaries could have a negative impact on its results of operations, financial condition and cash flows.

Risks Associated With Financing and Capital Structure

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

We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit provided by various financial institutions to support our hedging operations. We also deposit cash in short-term investments. Volatility in the capital and credit markets could adversely affect our ability to draw on our credit facilities and cash. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition.

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

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

Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our or Our Subsidiaries' Financing Costs, Ability to Access Capital and Requirement to Post Collateral and the Ability to Continue Successfully Implementing Our Retail Sales Strategy

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

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. A downgrade in our or our subsidiaries' credit ratings from the nationally recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. A downgrade in our credit rating, or that of our subsidiaries, could also preclude certain retail customers from executing supply contracts with us and therefore impact our ability to successfully implement our retail sales strategy. Furthermore, a downgrade could increase the cost of such capital by causing us to incur higher interest rates and fees associated with such capital. A rating downgrade would also increase the fees we pay on our various existing credit facilities, thus increasing the cost of our working capital. A rating downgrade could also impact our ability to grow our businesses by substantially increasing the cost of, or limiting access to, capital. See Note 16, Commitments, Guarantees and Contingencies - Guarantees and Other Assurances of the Combined Notes to Consolidated Financial Statements for more information associated with a credit ratings downgrade leading to the posting of cash collateral.

The Stability of Counterparties Could Adversely Affect Us

We are exposed to the risk that counterparties that owe us money, power, fuel or other commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Some of our agreements contain provisions that require the counterparties to provide credit support to secure all or part of their obligations to FirstEnergy or its subsidiaries. If the counterparties to these arrangements fail to perform, we may have a right to receive the proceeds from the credit support provided, however the credit support may not always be adequate to cover the related obligations. In such event, we may incur losses in addition to amounts, if any, already paid to the counterparties, including by being forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by customers or other counterparties may be greater than the estimates predict, which could have a material adverse effect on our results of operations and financial condition.

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

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

We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts they May be Paid and that the Recent Reduction in Our Dividend, or any Future Reductions Declared by our Board, Will Have a Positive Impact on Our Results of Operations

On January 21, 2014, in connection with actions taken to refocus our business strategy as a result of continuing weak economic conditions and depressed energy prices, our Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock, which equates to an indicated annual dividend of $1.44 per share and is lower than the $0.55 per share per quarter ($2.20 per share annually) that FirstEnergy previously paid since 2008. Our Board of Directors will continue to regularly evaluate our common stock dividend and determine an appropriate dividend each quarter taking into account such factors as, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past. Additionally, we cannot assure common shareholders that the recent reduction, or any future reduction, in our dividend will be successful in strengthening our results of operations and liquidity.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

The first mortgage indentures for the Ohio Companies, Penn, FG and NG constitute direct first liens on substantially all of the respective physical property, subject only to excepted encumbrances, as defined in the first mortgage indentures. See Notes 6, Leases, and 12, Capitalization, of the Combined Notes to Consolidated Financial Statements for information concerning leases and financing encumbrances affecting certain of the Utilities', FG's and NG's properties.

FirstEnergy controls the following generation sources as of February 24, 2014, shown in the table below. Except for the leasehold interests, OVEC participation and wind and solar power arrangements referenced in the footnotes to the table, substantially all of FES' competitive generating units are owned by NG (nuclear) and FG (non-nuclear); the regulated generating units are owned by JCP&L and MP. The table below excludes 527 MW of hydro generation sold on February 12, 2014. See Note 20, Discontinued Operations and Assets Held for Sale, for additional information regarding the asset sale.

| Plant (Location) | Unit | Total[(1)] | | Competitive FES | AE Supply | Regulated |
|---|---|---|---|---|---|---|
| | | Net Demonstrated Capacity (MW) | | | | |
| Super-critical Coal-fired: | | | | | | |
| Bruce Mansfield (Shippingport, PA) | 1 | 830 | (2) | 830 | — | — |
| Bruce Mansfield (Shippingport, PA) | 2 | 830 | | 830 | — | — |
| Bruce Mansfield (Shippingport, PA) | 3 | 830 | | 830 | — | — |
| Harrison (Haywood, WV) | 1-3 | 1,984 | | — | — | 1,984 |
| Pleasants (Willow Island, WV) | 1-2 | 1,300 | | — | 1,300 | — |
| W. H. Sammis (Stratton, OH) | 6-7 | 1,200 | | 1,200 | — | — |
| Fort Martin (Maidsville, WV) | 1-2 | 1,098 | | — | — | 1,098 |
| | | 8,072 | | 3,690 | 1,300 | 3,082 |
| Sub-critical and Other Coal-fired: | | | | | | |
| W. H. Sammis (Stratton, OH) | 1-5 | 1,020 | | 1,020 | — | — |
| Eastlake (Eastlake, OH) | 1-3 | 396 | (3) | 396 | — | — |
| Bay Shore (Toledo, OH) | 1 | 136 | | 136 | — | — |
| Lakeshore (Cleveland, OH) | 18 | 245 | (3) | 245 | — | — |
| Ashtabula (Ashtabula, OH) | 5 | 244 | (3) | 244 | — | — |
| OVEC (Cheshire, OH) (Madison, IN) | 1-11 | 188 | (4) | 110 | 67 | 11 |
| | | 2,229 | | 2,151 | 67 | 11 |
| Nuclear: | | | | | | |
| Beaver Valley (Shippingport, PA) | 1 | 939 | | 939 | — | — |
| Beaver Valley (Shippingport, PA) | 2 | 933 | (5) | 933 | — | — |
| Davis-Besse (Oak Harbor, OH) | 1 | 908 | | 908 | — | — |
| Perry (N. Perry Village, OH) | 1 | 1,268 | (6) | 1,268 | — | — |
| | | 4,048 | | 4,048 | — | — |
| Gas/Oil-fired: | | | | | | |
| AE Nos. 1, 2, 3, 4 & 5 (Springdale, PA) | 1-5 | 638 | | — | 638 | — |
| West Lorain (Lorain, OH) | 1-6 | 545 | | 545 | — | — |
| AE Nos. 12 & 13 (Chambersburg, PA) | 12-13 | 88 | | — | 88 | — |
| AE Nos. 8 & 9 (Gans, PA) | 8-9 | 88 | | — | 88 | — |
| Hunlock CT (Hunlock Creek, PA) | 1 | 45 | | — | 45 | — |
| Buchanan (Oakwood, VA) | 1-2 | 43 | (7) | — | 43 | — |
| Other | | 156 | | 156 | — | — |
| | | 1,603 | | 701 | 902 | — |
| Pumped-storage Hydro: | | | | | | |
| Bath County (Warm Springs, VA) | 1-6 | 1,200 | (8) | — | 713 | 487 |
| Yard's Creek (Blairstown Twp., NJ) | 1-3 | 200 | (9) | — | — | 200 |
| | | 1,400 | | — | 713 | 687 |
| Wind and Solar Power | | 496 | (10) | 496 | — | — |
| Total | | 17,848 | | 11,086 | 2,982 | 3,780 |

(1) Does not include Hatfield's Ferry and Mitchell power stations which were deactivated on October 9, 2013, the Mad River power station which was deactivated on January 9, 2014, and 527 MWs of hydro generation that are classified as held for sale as of December 31, 2013 and were sold on February 12, 2014.
(2) Includes FE's leasehold interest of 93.83% (779 MW) from non-affiliates.
(3) Remains active pursuant to RMR arrangements with PJM.
(4) Represents FG's 4.85%, AE Supply's 3.01% and MP's 0.49% entitlement based on their participation in OVEC.
(5) Includes OE’s leasehold interest of 2.60% (24 MW) from non-affiliates.
(6) Includes OE’s leasehold interest of 8.11% (103 MW) from non-affiliates.
(7) Buchanan Energy is a subsidiary of AE Supply. CNX Gas Corporation and Buchanan Energy have equal ownership interests in Buchanan Generation, LLC. AE Supply operates and dispatches 100% of Buchanan Generation, LLC's 86 MWs.
(8) Represents AGC's 40% interest in Bath County, a pumped-storage hydroelectric station. The station is operated by 60% owner Virginia Electric and Power Company.
(9) Represents JCP&L’s 50% ownership interest.
(10) Includes 167 MW from leased facilities and 329 MW under power purchase agreements.

The above generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. FirstEnergy's overhead and underground transmission lines aggregate 24,047 pole miles.

The Utilities' electric distribution systems include 267,640 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of approximately 148,828,225 kV-amperes.

All of FirstEnergy's generation, transmission and distribution assets operate in PJM.

FirstEnergy's distribution and transmission systems as of December 31, 2013, consist of the following:

| | Distribution Lines[1] | Transmission Lines[1] | Substation Transformer Capacity[2] kV Amperes |
|---|---|---|---|
| OE | 61,001 | 468 | 7,899,579 |
| Penn | 13,476 | 52 | 1,086,370 |
| CEI | 33,295 | — | 10,114,264 |
| TE | 18,970 | 81 | 2,978,453 |
| JCP&L | 23,020 | 2,592 | 21,989,461 |
| ME | 18,777 | 1,390 | 10,886,580 |
| PN | 27,301 | 3,171 | 14,954,052 |
| ATSI[3] | — | 7,525 | 26,262,434 |
| WP | 21,816 | 2,263 | 16,813,482 |
| MP | 25,388 | 2,126 | 15,379,374 |
| PE | 24,596 | 4,198 | 16,262,176 |
| TrAIL[4] | — | 181 | 4,202,000 |
| Total | 267,640 | 24,047 | 148,828,225 |

(1) Pole miles
(2) Top rating of in-service power transformers only. Excludes grounding banks, station power transformers, and generator and customer-owned transformers.
(3) Represents transmission line of 69kV and above located in the service areas of OE, Penn, CEI and TE.
(4) Represents transmission lines at 23kV located in the service areas of MP, PE and WP.

## ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 15, Regulatory Matters, and Note 16, Commitments, Guarantees and Contingencies of the Combined Notes to Consolidated Financial Statements for a description of certain legal proceedings involving FirstEnergy and FES.

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable

# PART II

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

The information required by Item 5 regarding FirstEnergy's market information, including stock exchange listings and quarterly stock market prices, dividends and holders of common stock is included in Item 6.

Information for FES is not disclosed because it is a wholly owned subsidiary of FirstEnergy and there is no market for its common stock.

Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy's 2014 proxy statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act.

The table below includes information regarding purchases of FE common stock during the fourth quarter of 2013:

| | Period | | | |
|---|---|---|---|---|
| | October | November | December | Fourth Quarter |
| Total Number of Shares Purchased[1] | 2,450 | 9,145 | 147,569 | 159,164 |
| Average Price Paid per Share | $38.18 | $34.95 | $32.74 | $32.95 |
| Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs[2] | — | — | — | — |
| Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs | — | — | — | — |

(1) Share amounts reflect purchases on the open market to satisfy FirstEnergy's obligations to deliver common stock for some or all of the following: 2007 Incentive Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan, Director Compensation, Allegheny Energy, Inc., 1998 Long-Term Incentive Plan, Allegheny Energy, Inc., 2008 Long-Term Incentive Plan, Allegheny Energy, Inc., Non-Employee Director Stock Plan, and Allegheny Energy, Inc., Amended and Restated Revised Plan for Deferral of Compensation of Directors.

(2) FirstEnergy does not currently have any publicly announced plan or program for share purchases.

ITEM 6. SELECTED FINANCIAL DATA

| For the Years Ended December 31, | 2013 | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|
| | (In millions, except per share amounts) | | | | |
| Revenues | $14,917 | $15,273 | $16,105 | $13,306 | $12,954 |
| Income From Continuing Operations | $375 | $755 | $856 | $696 | $847 |
| Earnings Available to FirstEnergy Corp. | $392 | $770 | $885 | $742 | $872 |
| Earnings per Share of Common Stock: | | | | | |
| Basic - Continuing Operations | $0.90 | $1.81 | $2.19 | $2.37 | $2.84 |
| Basic - Discontinued Operations (Note 20) | 0.04 | 0.04 | 0.03 | 0.07 | 0.03 |
| Basic - Earnings Available to FirstEnergy Corp. | $0.94 | $1.85 | $2.22 | $2.44 | $2.87 |
| | | | | | |
| Diluted - Continuing Operations | $0.90 | $1.80 | $2.18 | $2.35 | $2.82 |
| Diluted - Discontinued Operations (Note 20) | 0.04 | 0.04 | 0.03 | 0.07 | 0.03 |
| Diluted - Earnings Available to FirstEnergy Corp. | $0.94 | $1.84 | $2.21 | $2.42 | $2.85 |
| | | | | | |
| Weighted Average Shares Outstanding: | | | | | |
| Basic | 418 | 418 | 399 | 304 | 304 |
| Diluted | 419 | 419 | 401 | 305 | 306 |
| Dividends Declared per Share of Common Stock | $1.65 | $2.20 | $2.20 | $2.20 | $2.20 |
| Total Assets | $50,424 | $50,494 | $47,410 | $35,611 | $35,153 |
| Capitalization as of December 31: | | | | | |
| Total Equity | $12,695 | $13,093 | $13,299 | $8,952 | $9,014 |
| Long-Term Debt and Other Long-Term Obligations | 15,831 | 15,179 | 15,716 | 12,579 | 12,008 |
| Total Capitalization | $28,526 | $28,272 | $29,015 | $21,531 | $21,022 |

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.

| | 2013 | | 2012 | |
|---|---|---|---|---|
| | High | Low | High | Low |
| First Quarter | $42.50 | $38.26 | $46.59 | $40.37 |
| Second Quarter | $46.77 | $35.72 | $49.46 | $44.64 |
| Third Quarter | $39.88 | $35.46 | $51.14 | $42.05 |
| Fourth Quarter | $38.92 | $31.29 | $46.55 | $40.47 |
| Yearly | $46.77 | $31.29 | $51.14 | $40.37 |

Closing prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2008 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 103,266 and 102,914 holders of 418,628,559 and 418,734,086 shares of FirstEnergy's common stock as of December 31, 2013 and January 31, 2014, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12, Capitalization of the Combined Notes to Consolidated Financial Statements.

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

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "will," "intend," “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, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission plan and planned distribution rate cases and the effectiveness of our repositioning strategy.
- The impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases or the WVCAG's pending appeal of the Generation Resource Transaction.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as the polar vortex or other significant weather events.
- Regulatory outcomes associated with storm restoration, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and availability and their impact on retail margins.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water discharge, water intake and coal combustion residual regulations, the potential impacts of CSAPR, CAIR, and/or any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units including the impact on vendor commitments, and the timing thereof as they relate to, among other things, RMR arrangements and the reliability of the transmission grid.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building and the steam generator replacement at Davis-Besse.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.

- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals including, but not limited to, the ability to reduce costs and to successfully complete our announced financial plans designed to improve our credit metrics and strengthen our balance sheet, including but not limited to, the benefits from our announced dividend reduction and our proposed capital raising and debt reduction initiatives.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.
- The ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.

- Actions that may be taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.
See Item 1A. Risk Factors for additional information regarding risks that may impact our business, financial condition and results of operations.

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

Earnings available to FirstEnergy Corp. in 2013 were $392 million, or basic earnings of $0.94 per share of common stock ($0.94 diluted), compared with $770 million, or basic earnings of $1.85 per share of common stock ($1.84 diluted) in 2012 and $885 million, or $2.22 per basic share ($2.21 diluted), in 2011. The principal reasons for the changes in basic earnings per share are summarized below:

| Change In Basic Earnings Per Share From Prior Year | 2013 | 2012 |
|---|---|---|
| Basic Earnings Per Share - Prior Year | $1.85 | $2.22 |
| Segment operating results[(1)] - | | |
| Regulated Distribution | 0.06 | (0.05) |
| Regulated Transmission | (0.03) | — |
| Competitive Energy Services | (0.45) | (0.21) |
| Regulatory charges | (0.46) | (0.03) |
| Non-core asset sales/impairments | — | (0.78) |
| Merger-related costs | 0.03 | 0.36 |
| Merger accounting — commodity contracts | 0.05 | 0.11 |
| Net merger accretion[(1)(2)] | — | 0.01 |
| Trust securities impairments | (0.09) | 0.01 |
| Mark-to-market adjustments- | | |
| Pension and OPEB actuarial assumptions | 1.29 | (0.17) |
| All other | (0.07) | 0.13 |
| Plant deactivation costs | (0.74) | 0.20 |
| West Virginia asset transfer charges | (0.51) | — |
| Litigation resolution | — | 0.06 |
| Debt redemption costs | (0.20) | — |
| Restructuring costs | 0.01 | (0.02) |
| Interest expense, net of amounts capitalized | (0.01) | 0.04 |
| Investment income | — | (0.01) |
| Income tax legislative changes | 0.08 | (0.02) |
| Change in effective tax rate | 0.11 | (0.09) |
| Settlement of uncertain tax positions | — | 0.06 |
| Discontinued operations | — | 0.01 |
| Other | 0.02 | 0.02 |
| Basic Earnings Per Share | $0.94 | $1.85 |

(1) Excludes amounts that are shown separately.
(2) Includes dilutive effect of shares issued in connection with the Allegheny merger.

FirstEnergy continued to be exposed to weak economic conditions across its multi-state utility service territory throughout 2013, as evidenced by relatively flat distribution sales over the last three years. This prolonged decrease in demand, coupled with excess generation supply in the region, has caused a period of protracted low power and capacity prices. Further, the PJM RPM Auction for 2016/2017 capacity that was conducted in May 2013 produced prices in the regions served by FirstEnergy's Competitive Energy Services segment that were lower than expected. This result is a broader indication of an underlying supply/demand imbalance that is expected to continue to affect power producers in this region, adding pressure on already depressed energy prices and potentially pushing any significant power price recovery further into the future than FirstEnergy, or the industry at large, previously expected.

Over the course of 2013, FirstEnergy took a number of actions designed to reposition the Competitive Energy Services segment, including adjusting its hedging strategy by slowing forward sales in order to capture any potential future improvements in power prices, being more selective in the customers targeted and focusing more on customers with higher profit margins. With the deactivation of the Hatfield's Ferry and Mitchell plants and the Harrison/Pleasants asset transfer in October of 2013, as well as the sale of 527 MW of hydro assets on February 12, 2014, FirstEnergy has reduced the size of the competitive fleet and changed the mix of its assets. While these actions will result in the competitive fleet being about the same size as before the Allegheny merger, FirstEnergy believes it is a much stronger, more efficient, and environmentally controlled platform of units.

In late 2013, FirstEnergy announced plans to grow its regulated operations - specifically its transmission segment. FirstEnergy plans to implement a transmission expansion plan designed to improve operating flexibility, increase the reliability of the regional transmission system, position capacity for future load growth and facilitate response to system events. These investments will focus primarily in ATSI, which has a formula rate recovery mechanism, but will ultimately extend throughout FirstEnergy's service area.

Operational Matters

Employee Relations

As of December 31, 2013, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 48% of FirstEnergy's total employees. There are various CBAs between FirstEnergy's subsidiaries and these unions, most of which have three year terms. There were seven CBAs covering approximately 2,850 bargaining unit employees that expired in 2013. Negotiations on five of the seven CBAs resulted in new CBAs that expire in 2014, 2015, or 2016.

FirstEnergy is engaged in separate negotiations with Local 102 and Local 180 of the UWUA. The CBA with Local 102, which represents approximately 700 employees at WP and PE, expired on April 30, 2013. WP and PE have work continuation plans in place in the event of any work stoppage. The CBA with Local 180, which represents approximately 150 employees at PN, expired on August 31, 2013. After multiple bargaining sessions without an agreement on a new CBA, FirstEnergy issued a final offer, which Local 180 rejected. Beginning November 25, 2013, FirstEnergy locked out members of Local 180 and commenced its work continuation plan.

In addition, two other CBAs due to expire in 2014 were extended to 2017 prior to their expiration.

West Virginia Asset Transfer - 2013

On October 9, 2013, MP sold its approximate 8% share of Pleasants at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was repaid in the fourth quarter of 2013. In connection with the closing, in the fourth quarter of 2013, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Additionally, MP recognized a regulatory liability of approximately $23 million in the fourth quarter of 2013 representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station.

Hatfield's Ferry, Mitchell & Mad River Plant Deactivations

As a result of the cost of compliance with current and future environmental regulations and the continued low market price for electricity, FirstEnergy deactivated its 1,700-MW Hatfield's Ferry and 370-MW Mitchell coal-fired plants on October 9, 2013. In connection with the deactivations, in the second quarter of 2013, FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge is included within the results of the Competitive Energy Services segment.

Approximately 240 plant employees and generation related positions were affected by these plant deactivations. FirstEnergy recorded approximately $6 million (pre-tax) of severance related expenses that were recognized in Other operating expenses in the Consolidated Statements of Income for the year ended December 31, 2013.

On January 9, 2014, FirstEnergy deactivated the 60 MW Mad River power station in Springfield, Ohio as PJM found no reliability issues.

Davis-Besse Inspection

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirm that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

Nuclear Refueling Outages

The following table includes details for the two refueling outages in 2013:

| Unit | Outage Start | Returned to Service |
|---|---|---|
| Perry | March 18, 2013 | May 2, 2013 |
| Beaver Valley Unit 1 | September 30, 2013 | November 4, 2013 |

On March 18, 2013, Perry Nuclear Power Plant safely shut down for scheduled refueling, maintenance and a turbine upgrade. While the unit was off-line, 280 of the 748 fuel assemblies were replaced, and numerous safety inspections were conducted on the unit's reactor vessel, turbine and generator. In addition, preventative maintenance was performed on major components, including testing more than 160 valves, replacing several control rod blades and inspecting and cleaning cooling tower piping. During the outage, Perry's three low pressure turbines were replaced with new 175-ton turbine rotors.

On September 30, 2013, the 911 MW Beaver Valley Unit 1 entered into a scheduled refueling and maintenance outage, including a turbine upgrade that is designed to improve efficiency and reliability. During the outage, 60 of the 157 fuel assemblies were exchanged. Numerous inspections, maintenance activities and improvement projects designed to ensure continued safe and reliable operations have occurred. Prior to the outage, Beaver Valley operated safely and reliably for 507 consecutive days since the completion of its last refueling outage in May 2012.

Beaver Valley Unit 1 returned to service January 29, 2014, following replacement and testing of the Main Unit Transformer associated with a fault that occurred on January 6, 2014 that resulted in an automatic shutdown. In addition, during January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including Beaver Valley Unit 1, FirstEnergy's Competitive Energy Services segment (including FES) was required to purchase higher volumes of power. Given the market conditions in PJM, the Competitive Energy Services segment (including FES) also experienced increased levels of transmission charges, primarily associated with ancillary expenses, such as synchronous and operating reserves, which are intended for reliability purposes and are socialized across all load serving entities based on load share. Certain of these transmission charges are expected to be billed to retail customers.

On February 1, 2014, the Davis-Besse Nuclear Power Station entered into an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall will be repaired during this outage to conform to its original design configuration. This condition is not expected to extend the outage.

Regulatory Matters

Ohio Alternative Energy Rider Update

Under SB221 the Ohio Companies are required to serve part of their load from renewable energy sources. During 2009 through 2011, the Ohio Companies, in accordance with SB221, conducted RFPs to secure RECs. On August 7, 2013 the PUCO disallowed the Ohio Companies' recovery of $43.4 million, plus interest, that related to 2011 RECs that were purchased in the August 2010 RFP. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

Pennsylvania Marginal Transmission Losses

On September 30, 2013, the U.S. District Court granted the PPUC’s motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court’s decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

JCP&L Rate Filing Update

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. JCP&L's rate case petition was filed on November 30, 2012. JCP&L is requesting an increase in base rate revenues of approximately $20.6 million. Hearings in the rate case have concluded. Initial briefs were filed on January 27, 2014. In the initial briefs, the Division of Rate Counsel and the Staff of the NJBPU recommended current rate revenues be decreased by $214.9 million and $207.4 million, respectively. Such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012. Reply briefs were filed on February 24, 2014.

On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L’s $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Financial Matters

In early 2013, FirstEnergy announced a financial plan with the intention of strengthening the balance sheets of its subsidiaries. Completion of the plan was also expected to significantly improve credit metrics at the Competitive Energy Services segment and included the net transfer of 1,476 MW of the Harrison and Pleasants power plants between AE Supply and MP, and the proposed sale of up to 1,240 MW of unregulated hydro assets. In line with these efforts, FirstEnergy and its subsidiaries executed its 2013 financial plan as described below.

FE

On March 5, 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their tender offers. During the second quarter of 2013, FE also completed a $1.5 billion equity contribution to FES.

On September 25, 2013, FE filed a registration statement with the SEC to register 4 million shares of common stock to be issued to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan. In addition, during December 2013, FE began fulfilling certain share-based benefit plan obligations through the issuance of authorized but unissued common stock.

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

Competitive Energy Services

On March 28, 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. FES and AE Supply paid $67 million and $43 million, respectively, in premiums to repurchase the tendered senior notes.

On April 15, 2013 FES redeemed $400 million of its 4.8% senior notes due 2015 and paid $31 million of premiums in connection with the redemption.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

On September 4, 2013, FESC, on behalf of FG, AE Supply and Green Valley Hydro LLC applied for authorization from FERC to sell eleven hydroelectric power stations in Pennsylvania, Virginia and West Virginia to subsidiaries of Harbor Hydro, a subsidiary of LS Power. The hydroelectric power stations involved have a total generating capacity of approximately 527 MW, which represents less than 3 percent of FirstEnergy's competitive generation fleet output. An asset purchase agreement was entered into on August 23, and amended and restated as of September 4, 2013. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. In the first quarter of 2014, FirstEnergy expects to recognize a pre-tax gain of approximately $145 million (FES - $177 million) related to the sale.

On November 15, 2013, AE Supply optionally redeemed $235 million of its 7.00% PCRBs due July 15, 2039 at 100% of the principal amount in connection with the deactivation of operations at Hatfield's Ferry.

Regulated Distribution and Regulated Transmission

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME's 4.95% senior unsecured notes that matured in March 2013 and repay short-term debt.

In June 2013, the Ohio Companies, through newly formed limited liability SPEs, executed a securitization transaction that resulted in the issuance of approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48%. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020.

On August 21, 2013, JCP&L issued $500 million of 4.7% senior unsecured notes due April 1, 2024. The proceeds were used to pay down a portion of its short-term debt obligations, including borrowings incurred to finance a portion of Hurricane Sandy-related repair and restoration costs.

On August 28, 2013, the Ohio Companies redeemed an additional $660 million of long-term debt with interest rates ranging from 5.65% to 7.25% and maturities ranging from 2013 to 2020. In addition, approximately $120 million was paid in make-whole premiums which was deferred as a regulatory asset and will be amortized over the original life of the redeemed debt.

On October 9, 2013, MP sold its approximate 8% share of Pleasants Power Station at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison Power Station to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million.

On November 27, 2013, MP issued $400 million of 4.10% FMB due April 15, 2024 and $600 million of 5.40% FMB due December 15, 2043. Proceeds from this offering were used by MP to: (i) repay at maturity $300 million of its FMB, 7.95% Series due December 15, 2013; (ii) redeem $120 million of its FMB, 6.70% Series due June 15, 2014; (iii) repay the note payable to its affiliate, AE Supply; and (iv) for working capital needs and other general corporate purposes. In connection with the closing, in the fourth quarter of 2013, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station.

On December 26, 2013, PN redeemed $150 million of its 5.13% Senior Notes due April 1,2014 and ME redeemed $100 million of its 4.88% Senior Notes due April 1, 2014.

Overall, these actions, consisting of the 2013 financial plan, including debt reductions at the Competitive Energy Services segment and cost savings across all of its businesses, contributed to FirstEnergy's progress in achieving its financial goals for each of its businesses in 2013, including strengthening their balance sheets, improving their liquidity and maintaining their credit ratings.

FIRSTENERGY’S BUSINESS

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,780 MWs of generation capacity, including the net transfer to Regulated Distribution of 1,476 MWs of capacity associated with the Harrison and Pleasants asset swap which occurred on October 9, 2013.

The service areas of, and customers served by, our regulated distribution utilities are summarized below (in thousands):

| Company | Area Served | Customers Served |
|---|---|---|
| OE | Central and Northeastern Ohio | 1,034 |
| Penn | Western Pennsylvania | 161 |
| CEI | Northeastern Ohio | 745 |
| TE | Northwestern Ohio | 308 |
| JCP&L | Northern, Western and East Central New Jersey | 1,098 |
| ME | Eastern Pennsylvania | 556 |
| PN | Western Pennsylvania | 590 |
| WP | Southwest, South Central and Northern Pennsylvania | 720 |
| MP | Northern, Central and Southeastern West Virginia | 388 |
| PE | Western Maryland and Eastern West Virginia | 393 |
| | | 5,993 |

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM and excluding 1,476 MWs of generation capacity transferred to Regulated Distribution in connection with the Harrison and Pleasants asset swap that occurred on October 9, 2013. This segment also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of December 31, 2013, the percentage of expected physical sales economically hedged was 91% for 2014 (out of a 99 million MWH target). As of December 31, 2013, committed sales for 2015 and 2016 are approximately 49 million MWHs and 27 million MWHs, respectively.

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 19, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating unit. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

FirstEnergy engages in discussions with various commodity vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

STRATEGY AND OUTLOOK

FirstEnergy has taken a series of actions across the company to position itself for future growth. This includes repositioning its asset mix to reflect a more regulated business profile.

The strength of FirstEnergy is based on the diversity and scale of its operations. The following describes each operating segment's plans to pursue growth initiatives in spite of the downward pressures, such as declining energy prices, a multi-year recession and flat load growth, over the past several years.

Regulated Distribution

While customer demand is expected to grow only modestly over the next several years, FirstEnergy believes early indications of a sustained recovery, and the recent signs of growth in industrial sales are encouraging. In 2014, overall load growth is expected to be 0.6%, with the majority of the increase in the industrial sector. Since FirstEnergy's utility footprint overlays the Marcellus and Utica shale territories, it expects to benefit from the manufacturing expansion related to shale gas activity and has already seen 210 MWs of demand from new industrial projects placed in service, with an additional 430 MW of expected demand from planned expansions at customer facilities. These projects are expected to result in nearly 4 percent industrial load growth over the next two years.

From a regulatory perspective, FirstEnergy intends to be more active over the next several years in rate filings for its distribution utilities than it has in the past as it looks to modernize and improve the efficiency of its utility distribution system in order to continue to provide solid reliability to customers. For example, JCP&L has a pending rate case in New Jersey and MP plans to file a rate case in West Virginia in April 2014. In addition, Penn expects to seek approval to accelerate smart meter deployment beginning later this year, and one or more of the Pennsylvania Companies are expected to file rate cases later this year in Pennsylvania.

Regulated Transmission

FirstEnergy currently expects approximately $4.2 billion in transmission investments in 2014 through 2017 focused on improving system reliability and customer service along with addressing reliability requirements associated with plant deactivations or as required by NERC and PJM. These investments will initially focus on ATSI's 69kV system in Ohio and on TrAIL, both of which receive formula rate recovery, and then move across the entire FirstEnergy footprint over time.

Competitive Energy Services

Over the past two years, FirstEnergy has taken deliberate actions to change the character of its competitive generation fleet and to stabilize this business for the future. FirstEnergy has reduced the size of the fleet and changed the mix of assets. With the deactivations of the Hatfield and Mitchell power plants, the completion of the Harrison and Pleasants asset transfer in West Virginia, the sale of certain hydro assets and eventual deactivation of units currently operating under RMR arrangements with PJM, FirstEnergy’s competitive generating portfolio will consist of more than 13,000 MWs of diversified capacity, down from approximately 18,000 MWs at the beginning of 2013.

FirstEnergy also has significantly reduced projected capital expenditures for this segment by approximately $1 billion over the next four years. Competitive Energy Services segment spending for MATS is expected to be approximately $240 million, and the majority of the remaining capital investments will be focused on projects to extend the life of FirstEnergy's nuclear assets, including the planned installation of new steam generators at Davis-Besse in 2014, and new steam generators and a new reactor head at Beaver Valley Unit 2 in 2017.

Over the next several years FirstEnergy is targeting annual retail sales of approximately 100 million MWH, primarily supported by its competitive generation assets. FirstEnergy's competitive generation portfolio, excluding RMR units, is comprised of 38% supercritical coal, 10% subcritical coal, 31% nuclear, 12% gas and oil, and 9% renewables. In total, these generating assets make up one of the cleanest, lowest-cost generation fleets in the U.S. and are expected to generate between 75 and 80 million MWHs annually.

Overall, FirstEnergy's actions are expected to place its competitive operations in a much stronger position to manage through the current power market cycle, while also retaining upside potential if and when markets improve and limiting downside risk from continued depressed conditions associated with capacity prices and forward energy prices.

Financial Outlook

FirstEnergy endeavors to manage operating and capital costs in order to achieve its financial goals, including strengthening its balance sheet, improving liquidity, improving its credit metrics and maintaining investment grade metrics for the operating companies in its Regulated Distribution, Regulated Transmission and Competitive Energy Services segments.

In January 2014, FirstEnergy’s Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2014, to shareholders of record at the close of business on February 7, 2014. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008.

As of January 31, 2014, FirstEnergy’s available liquidity is $2.8 billion. Capital expenditures for 2014 are expected to be approximately $3.3 billion, an increase of $1 billion from 2013 primarily due to increased transmission investments. Over the next several years, these capital expenditures, including this transmission expansion program, are expected to be funded with a combination of debt, equity issuances through the stock investment and employee benefit plans, and the projected $320 million annually in cash preserved as a result of the dividend action taken in January 2014. The Utilities and FirstEnergy's competitive generation operations expect to fund their capital expenditures over the next several years through cash from operations, debt, and, depending on the operating company, equity contributions from FE. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to refinance short-term and maturing debt in the ordinary course, subject to market and other conditions. These actions are expected to continue the focus, in 2014, of maintaining strong balance sheets at the Utilities and the Competitive Energy Services segment.

The following represents a high level summary of assumptions and drivers that management expects will impact 2014 results of operations:

- Increased distribution revenue from projected sales of 148.8 million MWH in 2014 versus 147.9 million MWH in 2013.
- Increased transmission revenue due to increased investments at ATSI and TrAIL.
- Higher regulated generation operating margin primarily as a result of the West Virginia asset transfer which occurred in October 2013.
- Lower operations and maintenance expense due to reduced overall benefit expenses and lower expenses at the Competitive Energy Services segment resulting from the plant deactivations and asset sales, partially offset by increased expenses at the Regulated Distribution segment primarily due to increased maintenance costs for vegetation management.
- An effective income tax rate of 35% to 35.5%.
- Reduced commodity margin at the competitive operations.
- Two planned nuclear refueling outages in 2014, including an extended outage at Davis-Besse in 2014 for steam generator replacement, and outages at Beaver Valley Unit 1 for refueling and a transformer replacement.
- Increased pension/OPEB expense at the Regulated Distribution segment due to a lower asset balance and lower amortization of prior service cost credits.
- Higher net financing costs primarily due to higher interest expense.

Environmental Outlook

FirstEnergy continually strives to enhance environmental protection and remain good stewards of our natural resources. FirstEnergy also devotes significant resources to environmental compliance efforts, and its employees share a commitment to, and accountability for, environmental performance. The corporate focus on continuous improvement is integral to FirstEnergy's environmental programs.

More than $10 billion has been spent by FirstEnergy companies on environmental protection efforts since the initial passage of the Clean Air and Water Acts in the 1970s, and these investments demonstrate FirstEnergy’s continuing commitment to the environment. Recent investments of $3 billion at the Fort Martin and Sammis Plants further reduced emissions of $SO_2$ by over 95%, and NOx by at least 64% from these facilities. Since 1990, NOx emissions have been reduced by more than 80%, $SO_2$ by more than 90%, and mercury by approximately 70% at FirstEnergy generating units.

Aggressive steps have been taken by FirstEnergy to reduce its overall $CO_2$ emissions by 24% below 2005 levels, 7 years ahead of the Presidential 2020 goal of a 17% carbon pollution reduction below 2005 levels. In early 2012 and

2013, FirstEnergy announced its intent to deactivate 5,429 MW of older, coal-based generation, with 2,464 MWs deactivated in September 2012, another 2,080 MWs deactivated in October, 2013, and 885 MW remaining available to meet electric system reliability concerns pursuant to RMR arrangements with PJM. As a result of these further deactivations, FirstEnergy's $CO_2$ emissions are expected to continue to decline, depending on economic conditions.

FirstEnergy has taken a leadership role in pursuing new ventures to test and develop new technologies that may achieve additional reductions in $CO_2$ emissions. These include:

- Sales of over 1 million MWH per year of wind generation.
- $CO_2$ sequestration testing to gain a better understanding of the potential for geological storage of $CO_2$.
- Supporting afforestation - growing forests on non-forested land - and other efforts designed to remove $CO_2$ from the environment.
- Reducing emissions of $SF_6$ by more than 30% between 2011 and 2012, as reported to the EPA's Mandatory Greenhouse Gas Reporting Rule.
- Supporting research to develop and evaluate cost effective sorbent materials for $CO_2$ capture including work by EPRI and The University of Akron.

FirstEnergy remains actively engaged in the federal and state debate over future environmental requirements and legislation by actively working with policy makers and regulators to develop fair and reasonable requirements, with the goal of reducing emissions while minimizing the economic impact on customers. Due to the significant uncertainty as to the final form or timing of a significant number of regulations and legislation at both the federal and state levels, FirstEnergy is unable to determine the potential impact and risks associated with all future environmental requirements. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. On January 24, 2013, the EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. On December 10, 2013 the Supreme Court heard arguments on whether to reinstate the EPA's rule to reduce emissions of $SO_2$ and NOx, which is being challenged by several states and industry groups. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. The new MATS were finalized at the end of 2011, which contributed to FirstEnergy's decision to deactivate some of its older coal-fired generation plants. The total MATS compliance cost for the remaining fleet is estimated at $465 million with $240 million at the competitive fleet and $225 million at the regulated fleet.

FirstEnergy also has a long history of supporting research in distributed energy resources. Distributed energy resources include fuel cells, solar and wind systems or energy storage technologies located close to the customer or direct control of customer loads to provide alternatives or enhancements to the traditional electric power system. FirstEnergy is testing the world's largest utility-scale fuel cell system to determine its feasibility for augmenting generating capacity during summer peak-use periods. Through a partnership with EPRI, the Cuyahoga Valley National Park, the Department of Defense and Case Western Reserve University, two solid-oxide fuel cells were installed as part of a test program to explore the technology and the environmental benefits of distributed generation.

FirstEnergy is also evaluating the impact of distributed energy storage on the distribution system through analysis and field demonstrations of advanced battery technologies. FirstEnergy's EasyGreen® load-management program utilizes two-way communication capability with customers' non-critical equipment, such as air conditioners in New Jersey and Pennsylvania, to help manage peak loading on the electric distribution system. FirstEnergy has also made an online interactive energy efficiency tool, Home Energy Analyzer, available to our customers to help achieve electricity use reduction goals.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges. See ITEM 1A. RISK FACTORS for a discussion of the risks and challenges faced by FirstEnergy, FES and their subsidiaries.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis. A reconciliation of segment financial results is provided in Note 19, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with our sale of hydro assets discussed in additional detail in Note 20, Discontinued Operations and Assets Held for Sale. Net income by business segment was as follows:

| | | | | Increase (Decrease) | |
|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | 2013 vs 2012 | 2012 vs 2011 |
| | (In millions, except per share) | | | | |
| Net Income (Loss) By Business Segment: | | | | | |
| Regulated Distribution | $501 | $540 | $488 | $(39) | $52 |
| Regulated Transmission | 214 | 226 | 194 | (12) | 32 |
| Competitive Energy Services | (220) | 215 | 377 | (435) | (162) |
| Other and reconciling adjustments [1] | (103) | (210) | (190) | 107 | (20) |
| Net Income | $392 | $771 | $869 | $(379) | $(98) |
| | | | | | |
| Basic Earnings Per Share: | | | | | |
| Continuing operations | $0.90 | $1.81 | $2.19 | $(0.91) | $(0.38) |
| Discontinued operations (Note 20) | 0.04 | 0.04 | 0.03 | — | 0.01 |
| Net earnings per basic share | $0.94 | $1.85 | $2.22 | $(0.91) | $(0.37) |
| | | | | | |
| Diluted Earnings Per Share: | | | | | |
| Continuing operations | $0.90 | $1.80 | $2.18 | $(0.90) | $(0.38) |
| Discontinued operations (Note 20) | 0.04 | 0.04 | 0.03 | — | 0.01 |
| Net earnings per diluted share | $0.94 | $1.84 | $2.21 | $(0.90) | $(0.37) |

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

Summary of Results of Operations — 2013 Compared with 2012

Financial results for FirstEnergy’s business segments in 2013 and 2012 were as follows:

| 2013 Financial Results | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other and Reconciling Adjustments | FirstEnergy Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Revenues: | | | | | |
| External | | | | | |
| Electric | $8,499 | $741 | $5,542 | $(171) | $14,611 |
| Other | 239 | — | 183 | (116) | 306 |
| Internal | — | — | 770 | (770) | — |
| Total Revenues | 8,738 | 741 | 6,495 | (1,057) | 14,917 |
| Operating Expenses: | | | | | |
| Fuel | 377 | — | 2,119 | — | 2,496 |
| Purchased power | 3,308 | — | 1,425 | (770) | 3,963 |
| Other operating expenses | 1,773 | 131 | 2,007 | (318) | 3,593 |
| Pension and OPEB mark-to-market | (149) | — | (107) | — | (256) |
| Provision for depreciation | 606 | 114 | 439 | 43 | 1,202 |
| Amortization of regulatory assets, net | 529 | 10 | — | — | 539 |
| General taxes | 697 | 54 | 202 | 25 | 978 |
| Impairment of long-lived assets | 322 | — | 473 | — | 795 |
| Total Operating Expenses | 7,463 | 309 | 6,558 | (1,020) | 13,310 |
| Operating Income (Loss) | 1,275 | 432 | (63) | (37) | 1,607 |
| Other Income (Expense): | | | | | |
| Gain (loss) on debt redemptions | — | — | (149) | 17 | (132) |
| Investment income | 57 | — | 14 | (35) | 36 |
| Interest expense | (543) | (93) | (222) | (158) | (1,016) |
| Capitalized interest | 13 | 4 | 42 | 16 | 75 |
| Total Other Expense | (473) | (89) | (315) | (160) | (1,037) |
| Income (Loss) From Continuing Operations Before Income Taxes | 802 | 343 | (378) | (197) | 570 |
| Income taxes (benefits) | 301 | 129 | (141) | (94) | 195 |
| Income (Loss) From Continuing Operations | 501 | 214 | (237) | (103) | 375 |
| Discontinued Operations, net of tax | — | — | 17 | — | 17 |
| Net Income (Loss) | 501 | 214 | (220) | (103) | 392 |
| Income attributable to noncontrolling interest | — | — | — | — | — |
| Earnings (Losses) Available to FirstEnergy Corp. | $501 | $214 | $(220) | $(103) | $392 |

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| 2012 Financial Results | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other and Reconciling Adjustments | FirstEnergy Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Revenues: | | | | | |
| External | | | | | |
| Electric | $8,849 | $740 | $5,632 | $(214) | $15,007 |
| Other | 211 | — | 146 | (93) | 264 |
| Internal | — | — | 866 | (864) | 2 |
| Total Revenues | 9,060 | 740 | 6,644 | (1,171) | 15,273 |
| | | | | | |
| Operating Expenses: | | | | | |
| Fuel | 263 | — | 2,208 | — | 2,471 |
| Purchased power | 3,801 | — | 1,307 | (862) | 4,246 |
| Other operating expenses | 2,126 | 136 | 1,840 | (342) | 3,760 |
| Pension and OPEB mark-to-market | 392 | 2 | 215 | — | 609 |
| Provision for depreciation | 558 | 114 | 409 | 38 | 1,119 |
| Deferral of storm costs | (370) | (5) | — | — | (375) |
| Amortization of regulatory assets, net | 305 | 2 | — | — | 307 |
| General taxes | 706 | 44 | 209 | 25 | 984 |
| Total Operating Expenses | 7,781 | 293 | 6,188 | (1,141) | 13,121 |
| | | | | | |
| Operating Income | 1,279 | 447 | 456 | (30) | 2,152 |
| | | | | | |
| Other Income (Expense): | | | | | |
| Investment income | 84 | 1 | 66 | (74) | 77 |
| Interest expense | (540) | (92) | (284) | (85) | (1,001) |
| Capitalized interest | 12 | 3 | 44 | 13 | 72 |
| Total Other Expense | (444) | (88) | (174) | (146) | (852) |
| | | | | | |
| Income From Continuing Operations Before Income Taxes | 835 | 359 | 282 | (176) | 1,300 |
| Income taxes | 295 | 133 | 83 | 34 | 545 |
| Income From Continuing Operations | 540 | 226 | 199 | (210) | 755 |
| Discontinued Operations, net of tax | — | — | 16 | — | 16 |
| Net Income | 540 | 226 | 215 | (210) | 771 |
| Income attributable to noncontrolling interest | — | — | — | 1 | 1 |
| Earnings Available to FirstEnergy Corp. | $540 | $226 | $215 | $(211) | $770 |

| Changes Between 2013 and 2012 Financial Results<br>Increase (Decrease) | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other and Reconciling Adjustments | FirstEnergy Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Revenues: | | | | | |
| External | | | | | |
| Electric | $(350) | $ 1 | $(90) | $43 | $ (396) |
| Other | 28 | — | 37 | (23) | 42 |
| Internal | — | — | (96) | 94 | (2) |
| Total Revenues | (322) | 1 | (149) | 114 | (356) |
| | | | | | |
| Operating Expenses: | | | | | |
| Fuel | 114 | — | (89) | — | 25 |
| Purchased power | (493) | — | 118 | 92 | (283) |
| Other operating expenses | (353) | (5) | 167 | 24 | (167) |
| Pension and OPEB mark-to-market | (541) | (2) | (322) | — | (865) |
| Provision for depreciation | 48 | — | 30 | 5 | 83 |
| Deferral of storm costs | 370 | 5 | — | — | 375 |
| Amortization of regulatory assets, net | 224 | 8 | — | — | 232 |
| General taxes | (9) | 10 | (7) | — | (6) |
| Impairment of long-lived assets | 322 | — | 473 | — | 795 |
| Total Operating Expenses | (318) | 16 | 370 | 121 | 189 |
| | | | | | |
| Operating Income (Loss) | (4) | (15) | (519) | (7) | (545) |
| | | | | | |
| Other Income (Expense): | | | | | |
| Gain (loss) on debt redemptions | — | — | (149) | 17 | (132) |
| Investment income | (27) | (1) | (52) | 39 | (41) |
| Interest expense | (3) | (1) | 62 | (73) | (15) |
| Capitalized interest | 1 | 1 | (2) | 3 | 3 |
| Total Other Expense | (29) | (1) | (141) | (14) | (185) |
| | | | | | |
| Income (Loss) From Continuing Operations Before Income Taxes | (33) | (16) | (660) | (21) | (730) |
| Income taxes (benefits) | 6 | (4) | (224) | (128) | (350) |
| Income (Loss) From Continuing Operations | (39) | (12) | (436) | 107 | (380) |
| Discontinued Operations, net of tax | — | — | 1 | — | 1 |
| Net Income (Loss) | (39) | (12) | (435) | 107 | (379) |
| Income attributable to noncontrolling interest | — | — | — | (1) | (1) |
| Earnings (Losses) Available to FirstEnergy Corp. | $(39) | $ (12) | $(435) | $108 | $ (378) |

Regulated Distribution — 2013 Compared with 2012

Net income decreased by $39 million in 2013 compared to 2012, as more fully described below.

Revenues —

The $322 million decrease in total revenues resulted from the following sources:

| Revenues by Type of Service | For the Years Ended December 31, 2013 | 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Distribution services | $3,762 | $3,948 | $(186) |
| Generation sales: | | | |
| Retail | 3,959 | 4,104 | (145) |
| Wholesale | 330 | 347 | (17) |
| Total generation sales | 4,289 | 4,451 | (162) |
| Transmission | 448 | 450 | (2) |
| Other | 239 | 211 | 28 |
| Total Revenues | $8,738 | $9,060 | $(322) |

The decrease in distribution services revenue is primarily the result of a NJBPU-approved reduction to the JCP&L NUG Rider which was effective March 1, 2012 and a decrease to the ME and PN NUG riders resulting from the expiration of certain NUG contracts in 2012 and 2013. Additionally, lower recovery of energy efficiency expenses reflecting reduced costs was partially offset by an increase in the Ohio Companies' DCR rider and slightly higher distribution deliveries. Distribution deliveries increased by 0.9% in 2013 compared to 2012. Distribution deliveries by customer class are summarized in the following table:

| Electric Distribution MWH Deliveries | For the Years Ended December 31, 2013 | 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In thousands) | | |
| Residential | 54,479 | 53,993 | 0.9 % |
| Commercial | 42,582 | 42,645 | (0.1)% |
| Industrial | 50,243 | 49,378 | 1.8 % |
| Other | 584 | 585 | (0.2)% |
| Total Electric Distribution MWH Deliveries | 147,888 | 146,601 | 0.9 % |

Higher deliveries to residential customers primarily reflects increased weather-related usage resulting from heating degree days that were 18% above 2012, and 2% above normal, partially offset by cooling degree days that were 15% below 2012, and 3% above normal. Lower deliveries to the commercial sector primarily reflect increasing energy efficiency mandates and demand response initiatives. In the industrial sector, increased sales to steel, chemical, and shale gas customers were partially offset by lower sales to automotive and paper customers. Additionally, FirstEnergy expects additional growth in the industrial sector beyond 2013 for potential shale gas projects. As the gas fields are developed, the opportunity for additional manufacturing expansion could further support growth.

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The following table summarizes the price and volume factors contributing to the $162 million decrease in generation revenues in 2013 compared to 2012:

| Source of Change in Generation Revenues | Increase (Decrease) (In millions) |
|---|---|
| Retail: | |
| Effect of decrease in sales volumes | $(194) |
| Change in prices | 49 |
| | (145) |
| Wholesale: | |
| Effect of decrease in sales volumes | (95) |
| Change in prices | 78 |
| | (17) |
| Decrease in Generation Revenues | $(162) |

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during 2013, compared to 2012. This increased customer shopping, which does not impact earnings for the Regulated Distribution segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 81% from 79% for the Ohio Companies, 66% from 64% for the Pennsylvania Companies, 47% from 46% for PE and 52% from 50% for JCP&L. The increase in prices reflects the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs beginning in June 2013.

The decrease in wholesale generation revenues of $17 million in 2013 resulted from the expiration of NUG contracts, partially offset by higher energy and capacity prices in 2013.

Other revenues increased by $28 million primarily due to more customer requested work for OE and JCP&L in 2013 compared to 2012.

Operating Expenses —

Total operating expenses decreased by $318 million primarily due to the following:

- Fuel expense was $114 million higher in 2013 primarily related to increased generation at Fort Martin as a result of planned and forced outages in 2012 and the asset transfer between MP and AE Supply of the Harrison Power Station effective October 9, 2013.

- Purchased power costs were $493 million lower in 2013 primarily due to a decrease in volumes required as a result of increased customer shopping, higher generation, reduced NUG purchases and lower unit power supply costs.

| Source of Change in Purchased Power | Increase(Decrease) (In millions) |
|---|---|
| Purchases from non-affiliates: | |
| Change due to decreased unit costs | $ (68) |
| Change due to decreased volumes | (429) |
| | (497) |
| Purchases from affiliates: | |
| Change due to decreased unit costs | (10) |
| Change due to decreased volumes | (92) |

| | |
|---|---|
| | (102 ) |
| Decrease in costs deferred | 106 |
| Decrease in Purchased Power Costs | $ (493 ) |

- Other operating expenses decreased $353 million primarily due to:

- a decrease in energy efficiency program expenses of $40 million resulting from the completion of certain initiatives in Ohio and Pennsylvania, which are recoverable through rates;

- lower distribution operating and maintenance expenses of $363 million due to lower storm related maintenance activities during 2013 compared to 2012. Maintenance costs in 2012 related to Hurricane Sandy and the "derecho" wind storm totaled $386 million;

- higher transmission expenses of $50 million primarily due to PJM transmission costs associated with RMR units.

- Pension and OPEB mark-to-market charges decreased $541 million, primarily reflecting a higher discount rate to measure related obligations in 2013.

- Depreciation expense increased by $48 million due to a higher asset base.

- Deferral of storm costs decreased by $370 million primarily related to the absence of storm restoration expenses associated with Hurricane Sandy and the "derecho" wind storm.

- Net regulatory asset amortization increased $224 million primarily due to regulatory asset charges associated with the recovery of marginal transmission losses at ME and PN ($254 million), recovery of RECs for the Ohio Companies ($51 million), and the asset transfer between MP and AE Supply ($23 million) as well as higher default generation service cost recovery in Pennsylvania, partially offset by a reduction of NUG cost recovery at ME and PN and higher transmission cost deferrals in Ohio.

- General taxes decreased by $9 million primarily due to lower gross receipts and payroll taxes, partially offset by higher property taxes.

- Impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of Harrison to the amount permitted to be included in rate base.

Other Expense —

Other expense increased $29 million in 2013 primarily due to lower investment income resulting from the liquidation of investments at Shippingport and lower NDT investment income.

Regulated Transmission — 2013 Compared with 2012

Net income decreased by $12 million in 2013 compared to 2012, as further described below.

Revenues —

Total revenues increased by $1 million principally due to higher revenue requirements at ATSI and TrAIL, partially offset by lower PJM network service revenues for the Utilities, reflecting lower peak loads from the prior year.

Revenues by transmission asset owner are shown in the following table:

| | For the Years Ended December 31, | | Increase |
|---|---|---|---|
| Revenues by Transmission Asset Owner | 2013 | 2012 | (Decrease) |

| | | | |
|---|---|---|---|
| | (In millions) | | |
| ATSI | $219 | $213 | $6 |
| TrAIL | 207 | 200 | 7 |
| PATH | 20 | 18 | 2 |
| Utilities | 295 | 309 | (14) |
| Total Revenues | $741 | $740 | $1 |

Operating Expenses —

Total operating expenses increased by $16 million principally due to higher regulatory asset amortization related to the PATH abandonment and higher property taxes reflecting a higher asset base.

Competitive Energy Services — 2013 Compared with 2012

Net income decreased by $435 million in 2013, compared to 2012, as more fully described below.

Revenues —

Total revenues decreased by $149 million in 2013, compared to 2012, primarily due to a decline in wholesale sales. Although MWH sales increased 5.8% compared to the prior period, revenues were adversely impacted by lower unit prices compared to 2012 as a result of a significant decrease in power prices beginning in the fourth quarter of 2011 when the 2013 competitive retail sales position was only approximately 50% committed. These decreases were partially offset by growth in Governmental Aggregation, Mass Market, and POLR and Structured sales channels. The decrease in total revenues resulted from the following sources:

| Revenues by Type of Service | For the Years Ended December 31, 2013 | 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Direct | $2,913 | $2,934 | $(21) |
| Governmental Aggregation | 1,185 | 1,029 | 156 |
| Mass Market | 448 | 352 | 96 |
| POLR and Structured | 1,279 | 1,265 | 14 |
| Wholesale[1] | 341 | 751 | (410) |
| Transmission | 144 | 160 | (16) |
| RECs | 2 | 7 | (5) |
| Other | 183 | 146 | 37 |
| Total Revenues | $6,495 | $6,644 | $(149) |

[1] Excludes wholesale revenues classified as Discontinued Operations.

| MWH Sales by Channel | For the Years Ended December 31, 2013 | 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In thousands) | | |
| Direct | 56,145 | 54,528 | 3.0% |
| Governmental Aggregation | 20,859 | 17,287 | 20.7% |
| Mass Market | 6,761 | 5,212 | 29.7% |
| POLR and Structured | 24,805 | 22,664 | 9.4% |
| Wholesale[1] | 1,250 | 4,091 | (69.4)% |
| Total MWH Sales | 109,820 | 103,782 | 5.8% |

[1] Excludes wholesale sales classified as Discontinued Operations.

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

| MWH Sales Channel: | Source of Change in Revenues Increase (Decrease) Sales Volumes | Prices | Gain on Settled Contracts | Capacity Revenue | Total |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Direct | $87 | $(108) | $— | $— | $(21) |
| Governmental Aggregation | 213 | (57) | — | — | 156 |
| Mass Market | 105 | (9) | — | — | 96 |
| POLR and Structured Sales | 130 | (116) | — | — | 14 |
| Wholesale[1] | (74) | 4 | (204) | (136) | (410) |

[1] Excludes wholesale sales classified as Discontinued Operations.

The decrease in Direct revenues of $21 million resulted from lower unit prices, partially offset by higher sales volumes due to the acquisition of new larger customers in central and southern Ohio. The increase in Governmental Aggregation of $156 million resulted from the acquisition of new customers primarily in Illinois, partially offset by lower unit prices. The increase in Mass Market of $96 million resulted from the acquisition of new customers primarily in Ohio, Illinois and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of December 31, 2013, as compared to 2.6 million as of December 31, 2012.

The increase in POLR and structured revenues of $14 million was due to higher structured sales, partially offset by lower prices and lower POLR sales. The decline in POLR sales is in line with FES' strategy to realign its sales portfolio.

Wholesale revenues decreased $410 million due to a $204 million reduction in gains on financially settled contracts, a $136 million decrease in capacity revenues primarily from lower capacity prices, and a $70 million decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available for sale primarily as a result of the asset transfer between MP and AE Supply, plants that were deactivated in 2012 and 2013, and those under RMR arrangements, and higher retail sales volumes.

Transmission revenue decreased $16 million due primarily to lower congestion and ancillary revenue.

Other revenue increased $37 million due primarily to an $17 million pre-tax gain on the sale of property to a regulated affiliate and a $19 million increase in income from FEV's equity method investment in Global Holding.

Operating Expenses —

Total operating expenses increased by $370 million in 2013 due to the following:

- Fuel costs decreased $89 million primarily due to lower volumes associated with plants that were deactivated in 2013 and 2012, those under RMR arrangements, the asset transfer between MP and AE Supply and lower unit prices associated with new and restructured contracts, partially offset by settlements associated with past damages on transportation contracts.

- Purchased power costs increased $118 million due to higher volumes ($402 million) and increased prices ($81 million), partially offset by reduced losses on financially settled contracts ($239 million) and lower capacity expenses

($126 million). The increase in rate primarily resulted from higher on-peak prices compared to 2012. The increase in purchased power volumes relates to the overall increase in sales volumes and decrease in fossil generation.

- Fossil operating costs decreased by $25 million due primarily to lower labor costs resulting from previously deactivated units and lower compensation and benefit expenses associated with plan changes.
- Nuclear operating costs decreased by $21 million due primarily to lower labor costs and lower compensation and benefit expenses associated with plan changes.
- Transmission expenses increased $101 million due primarily to higher retail load and higher network costs associated with POLR sales in Pennsylvania, partially offset by lower congestion costs as well as credits received in 2013 for previously incurred PJM transmission costs associated with RMR units in the ATSI zone. Effective June 1, 2013, network transmission costs became the responsibility of suppliers of POLR sales in Pennsylvania.
- Impairments of long-lived assets increased $473 million due to the decision to deactivate the Hatfield and Mitchell generating plants. The plants were deactivated on October 9, 2013.

- General taxes decreased by $7 million due primarily to lower payroll taxes as a result of lower labor costs noted above, partially offset by higher property taxes.
- Depreciation expense increased $30 million primarily due to a higher asset base and accelerated depreciation associated with the deactivations noted above.
- Other operating expenses decreased by $210 million primarily due to a $322 million decrease in pensions and OPEB mark-to-market charges primarily reflecting a higher discount rate to measure related obligations in 2013, partially offset by an increase in mark-to-market expense on commodity contract positions ($98 million) and increased retail expenses ($26 million).

Other Expense —

Total other expense in 2013 increased $141 million compared to 2012 due to a $149 million loss on debt redemptions in connection with senior notes that were repurchased, lower investment income of $52 million due to higher OTTI on the NDT investments, partially offset by lower net interest expense of $60 million due to debt redemptions and repurchases.

Other — 2013 Compared with 2012

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 $107 million increase in net income in 2013 compared to 2012 primarily due to lower income tax expense of $128 million primarily resulting from reduced pre-tax income and a lower effective tax rate and increased investment income of $39 million. Partially offsetting the increase was higher interest expense of $73 million due to the issuance of $1.5 billion of senior unsecured notes in the first quarter of 2013.

Summary of Results of Operations — 2012 Compared with 2011

Financial results for FirstEnergy's business segments in 2012 and 2011 were as follows:

| 2012 Financial Results | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other and Reconciling Adjustments | FirstEnergy Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Revenues: | | | | | |
| External | | | | | |
| Electric | $8,849 | $ 740 | $5,632 | $(214) | $ 15,007 |
| Other | 211 | — | 146 | (93) | 264 |
| Internal | — | — | 866 | (864) | 2 |
| Total Revenues | 9,060 | 740 | 6,644 | (1,171) | 15,273 |
| | | | | | |
| Operating Expenses: | | | | | |
| Fuel | 263 | — | 2,208 | — | 2,471 |
| Purchased power | 3,801 | — | 1,307 | (862) | 4,246 |
| Other operating expenses | 2,126 | 136 | 1,840 | (342) | 3,760 |
| Pension and OPEB mark-to-market | 392 | 2 | 215 | — | 609 |
| Provision for depreciation | 558 | 114 | 409 | 38 | 1,119 |
| Deferral of storm costs | (370) | (5) | — | — | (375) |
| Amortization of regulatory assets, net | 305 | 2 | — | — | 307 |
| General taxes | 706 | 44 | 209 | 25 | 984 |
| Total Operating Expenses | 7,781 | 293 | 6,188 | (1,141) | 13,121 |
| | | | | | |
| Operating Income | 1,279 | 447 | 456 | (30) | 2,152 |
| | | | | | |
| Other Income (Expense): | | | | | |
| Investment income | 84 | 1 | 66 | (74) | 77 |
| Interest expense | (540) | (92) | (284) | (85) | (1,001) |
| Capitalized interest | 12 | 3 | 44 | 13 | 72 |
| Total Other Expense | (444) | (88) | (174) | (146) | (852) |
| | | | | | |
| Income From Continuing Operations Before Income Taxes | 835 | 359 | 282 | (176) | 1,300 |
| Income taxes | 295 | 133 | 83 | 34 | 545 |
| Income From Continuing Operations | 540 | 226 | 199 | (210) | 755 |
| Discontinued Operations, net of tax | — | — | 16 | — | 16 |
| Net Income | 540 | 226 | 215 | (210) | 771 |
| Income attributable to noncontrolling interest | — | — | — | 1 | 1 |
| Earnings Available to FirstEnergy Corp. | $540 | $ 226 | $215 | $(211) | $ 770 |

| 2011 Financial Results | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other and Reconciling Adjustments | FirstEnergy Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Revenues: | | | | | |
| External | | | | | |
| Electric | $9,689 | $ 660 | $5,616 | $(24) | $ 15,941 |
| Other | 224 | — | 167 | (294) | 97 |
| Internal | — | — | 1,237 | (1,170) | 67 |
| Total Revenues | 9,913 | 660 | 7,020 | (1,488) | 16,105 |
| | | | | | |
| Operating Expenses: | | | | | |
| Fuel | 268 | — | 2,049 | — | 2,317 |
| Purchased power | 4,667 | — | 1,379 | (1,172) | 4,874 |
| Other operating expenses | 1,842 | 113 | 2,241 | (247) | 3,949 |
| Pension and OPEB mark-to-market | 290 | 2 | 215 | — | 507 |
| Provision for depreciation | 523 | 104 | 411 | 24 | 1,062 |
| Deferral of storm costs | (145) | — | — | — | (145) |
| Amortization of regulatory assets, net | 468 | 6 | — | — | 474 |
| General taxes | 717 | 40 | 199 | 21 | 977 |
| Impairment of long-lived assets | 87 | — | 315 | 11 | 413 |
| Total Operating Expenses | 8,717 | 265 | 6,809 | (1,363) | 14,428 |
| | | | | | |
| Operating Income | 1,196 | 395 | 211 | (125) | 1,677 |
| | | | | | |
| Other Income (Expense): | | | | | |
| Gain on partial sale of Signal Peak | — | — | 569 | — | 569 |
| Investment income | 99 | — | 56 | (41) | 114 |
| Interest expense | (530) | (89) | (298) | (91) | (1,008) |
| Capitalized interest | 10 | 2 | 40 | 18 | 70 |
| Total Other Income (Expense) | (421) | (87) | 367 | (114) | (255) |
| | | | | | |
| Income From Continuing Operations Before Income Taxes | 775 | 308 | 578 | (239) | 1,422 |
| Income taxes | 287 | 114 | 214 | (49) | 566 |
| Income From Continuing Operations | 488 | 194 | 364 | (190) | 856 |
| Discontinued Operations, net of tax | — | — | 13 | — | 13 |
| Net Income | 488 | 194 | 377 | (190) | 869 |
| Income (loss) attributable to noncontrolling interest | — | — | — | (16) | (16) |
| Earnings Available to FirstEnergy Corp. | $488 | $ 194 | $377 | $(174) | $ 885 |

| Changes Between 2012 and 2011 Financial Results Increase (Decrease) | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other and Reconciling Adjustments | FirstEnergy Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Revenues: | | | | | |
| External | | | | | |
| Electric | $(840) | $ 80 | $16 | $(190) | $(934) |
| Other | (13) | — | (21) | 201 | 167 |
| Internal | — | — | (371) | 306 | (65) |
| Total Revenues | (853) | 80 | (376) | 317 | (832) |
| | | | | | |
| Operating Expenses: | | | | | |
| Fuel | (5) | — | 159 | — | 154 |
| Purchased power | (866) | — | (72) | 310 | (628) |
| Other operating expenses | 284 | 23 | (401) | (95) | (189) |
| Pension and OPEB mark-to-market | 102 | — | — | — | 102 |
| Provision for depreciation | 35 | 10 | (2) | 14 | 57 |
| Deferral of storm costs | (225) | (5) | — | — | (230) |
| Amortization of regulatory assets, net | (163) | (4) | — | — | (167) |
| General taxes | (11) | 4 | 10 | 4 | 7 |
| Impairment of long-lived assets | (87) | — | (315) | (11) | (413) |
| Total Operating Expenses | (936) | 28 | (621) | 222 | (1,307) |
| | | | | | |
| Operating Income | 83 | 52 | 245 | 95 | 475 |
| | | | | | |
| Other Income (Expense): | | | | | |
| Gain on partial sale of Signal Peak | — | — | (569) | — | (569) |
| Investment income | (15) | 1 | 10 | (33) | (37) |
| Interest expense | (10) | (3) | 14 | 6 | 7 |
| Capitalized interest | 2 | 1 | 4 | (5) | 2 |
| Total Other Expense | (23) | (1) | (541) | (32) | (597) |
| | | | | | |
| Income From Continuing Operations Before Income Taxes | 60 | 51 | (296) | 63 | (122) |
| Income taxes | 8 | 19 | (131) | 83 | (21) |
| Income From Continuing Operations | 52 | 32 | (165) | (20) | (101) |
| Discontinued Operations, net of tax | — | — | 3 | — | 3 |
| Net Income | 52 | 32 | (162) | (20) | (98) |
| Income attributable to noncontrolling interest | — | — | — | 17 | 17 |
| Earnings Available to FirstEnergy Corp. | $52 | $ 32 | $(162) | $(37) | $(115) |

Regulated Distribution — 2012 Compared with 2011

Net income increased by $52 million in 2012 compared to 2011, primarily due to two additional months of earnings from the Allegheny Utilities and lower merger-related costs, partially offset by decreased weather-related customer usage in 2012.

Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis.

Revenues —

The $853 million decrease in total revenues resulted from the following sources:

| Revenues by Type of Service | For the Years Ended December 31, 2012 | 2011 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Pre-merger companies: | | | |
| Distribution services | $3,247 | $3,428 | $(181) |
| Generation sales: | | | |
| Retail | 2,540 | 3,266 | (726) |
| Wholesale | 206 | 377 | (171) |
| Total generation sales | 2,746 | 3,643 | (897) |
| Transmission | 300 | 219 | 81 |
| Other | 167 | 180 | (13) |
| Total pre-merger companies | 6,460 | 7,470 | (1,010) |
| Allegheny Utilities[(1)] | 2,600 | 2,443 | 157 |
| Total Revenues | $9,060 | $9,913 | $(853) |

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

The decrease in distribution services revenue for the pre-merger companies reflects lower distribution deliveries (described below), the suspension of Ohio's deferred distribution cost recovery rider in December 2011 and an NJBPU-approved reduction to the JCP&L NUG Rider which became effective on March 1, 2012, partially offset by an increase in Ohio's energy efficiency rider and a PPUC-approved increase to the ME and PN NUG Riders which also became effective on March 1, 2012. Distribution deliveries (excluding the Allegheny Utilities) decreased by 1.7% in 2012 from 2011. Distribution deliveries by customer class are summarized in the following table:

| Electric Distribution MWH Deliveries | Year Ended December 31 2012 | 2011 | Increase (Decrease) |
|---|---|---|---|
| | (In thousands) | | |
| Pre-merger companies: | | | |
| Residential | 38,493 | 39,369 | (2.2)% |
| Commercial | 32,149 | 32,610 | (1.4)% |
| Industrial | 35,139 | 35,637 | (1.4)% |
| Other | 492 | 513 | (4.1)% |
| Total pre-merger companies | 106,273 | 108,129 | (1.7)% |

| | | | | |
|---|---|---|---|---|
| Allegheny Utilities[1] | 40,328 | 33,449 | 20.6 | % |
| Total Electric Distribution MWH Deliveries | 146,601 | 141,578 | 3.5 | % |

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

Lower deliveries to residential and commercial customers for the pre-merger companies primarily reflect decreased weather-related usage resulting from heating degree days that were 10% below 2011 levels, a slight reduction in the number of residential customers and declining average customer consumption caused, in part by, increasing energy efficiency mandates and demand response initiatives. In the industrial sector, MWH deliveries decreased 1.4%, reflecting slight decreases in deliveries to steel, petroleum and automotive customers.

The following table summarizes the price and volume factors contributing to the $897 million decrease in generation revenues for the pre-merger companies in 2012 compared to 2011:

| Source of Change in Generation Revenues | Decrease (In millions) |
|---|---|
| Retail: | |
| Effect of decrease in sales volumes | $(587) |
| Change in prices | (139) |
| | (726) |
| Wholesale: | |
| Effect of decrease in sales volumes | (120) |
| Change in prices | (51) |
| | (171) |
| Decrease in Generation Revenues | $(897) |

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories in 2012, compared with 2011. This increased customer shopping, which does not impact earnings for the Regulated Distribution segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 79% from 76% for the Ohio Companies, 64% from 52% for ME's, PN's and Penn's service areas and 50% from 44% for JCP&L. The decrease in retail generation prices resulted from the impact of lower auction prices on power supply prices in 2012 compared to 2011, partially offset by a full year of Ohio's RER Rider (recovers deferred costs relating to electric heating discounts).

The decrease in wholesale generation revenues of $171 million in 2012 resulted from the expiration and termination of NUG contracts in August 2011 and April 2012, lower capacity revenues and lower PJM market prices.

Transmission revenues increased $81 million primarily due to the implementation of Ohio's NMB transmission rider in June of 2011, which recovers network integration transmission service costs as describer further below.

The Allegheny companies added $157 million to revenues in 2012, including $136 million for distribution services and $43 million from generation sales, partially offset by a decrease of $19 million of transmission revenues and $3 million of other revenues.

Operating Expenses —

Total operating expenses decreased by $936 million in 2012. Excluding the Allegheny Utilities, total operating expenses decreased by $897 million due to the following:

- Purchased power costs, excluding the Allegheny Utilities, were $890 million lower in 2012 primarily due to a decrease in volumes required from increased customer shopping, the impact of milder weather and lower unit power supply costs during 2012 compared to 2011 as a result of lower auction prices.

| Source of Change in Purchased Power | Increase(Decrease) (In millions) |
|---|---|
| Purchases from non-affiliates: | |
| Change due to decreased unit costs | $ (149) |

| | |
|---|---|
| Change due to decreased volumes | (490) |
| | (639) |
| Purchases from affiliates: | |
| Change due to decreased unit costs | (65) |
| Change due to decreased volumes | (257) |
| | (322) |
| Decrease in costs deferred | 71 |
| Decrease in Purchased Power Costs | $ (890) |

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- Transmission expenses increased $115 million during 2012 compared to 2011. The increase is primarily due to network integration transmission service expenses that, prior to June 2011, were incurred by the generation supplier, and are now being recovered through the NMB transmission rider referred to above.
- Other operation and maintenance expenses increased $197 million primarily due to higher labor, professional contractor and material costs to repair storm-related damage.
- Energy Efficiency program costs, which are recovered through rates, increased by $16 million.
- Other costs decreased due to the absence of a provision for excess and obsolete material of $13 million that was recognized in 2011 relating to revised inventory practices adopted in conjunction with the Allegheny merger.
- Merger-related costs decreased $60 million in 2012 compared to 2011.
- Pension and OPEB mark-to-market charges increased $87 million, reflecting lower discount rates to measure related obligations in 2012.
- Depreciation expense increased by $27 million due to a higher asset base.
- Deferral of storm costs increased by $186 million primarily related to storm restoration expenses associated with Hurricane Sandy and the "derecho" wind storm.
- Net regulatory asset amortization decreased $162 million primarily due to the scheduled suspension of the Ohio rider recovering deferred distribution costs in December 2011 and the rate reduction for JCP&L's NUG deferred cost recovery in March of 2012, partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011.
- General taxes decreased by $28 million primarily due to a decrease in revenue-related taxes.

Operating expenses for the Allegheny Utilities are summarized in the following table:

| Operating Expenses - Allegheny[1] | For the Years Ended December 31, 2012 | 2011 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Purchased Power | $1,170 | $1,146 | $24 |
| Fuel | 263 | 268 | (5) |
| Transmission | 180 | 184 | (4) |
| Deferral of storm costs | (49) | (10) | (39) |
| Amortization of other regulatory assets, net | (14) | (13) | (1) |
| Pensions and OPEB mark-to-market adjustment | 91 | 76 | 15 |
| Other operating expenses | 273 | 240 | 33 |
| General taxes | 130 | 113 | 17 |
| Depreciation | 152 | 144 | 8 |
| Impairment of long-lived assets[2] | — | 87 | (87) |
| Total Operating Expenses | $2,196 | $2,235 | $(39) |

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.
(2) Deactivation of three regulated coal-fired fossil generating plants in West Virginia.

Other Expense —

Other expense increased $23 million in 2012 primarily due to higher interest expense on debt of the Allegheny Utilities and lower investment income on OE's and TE's NDT assets and the PNBV and Shippingport trusts.

Regulated Transmission — 2012 Compared with 2011

Net income increased by $32 million in 2012 compared to 2011 primarily due to two additional months of earnings in 2012 associated with TrAIL, PATH, and the Allegheny Utilities' transmission assets that were acquired in the merger.

Revenues —

Total revenues increased by $80 million principally due to revenues from TrAIL, PATH and the Allegheny Utilities' transmission assets in 2012 compared to 2011.

Revenues by transmission asset owner are shown in the following table:

| Revenues by Transmission Asset Owner | For the Years Ended December 31, 2012 | 2011 | Increase |
|---|---|---|---|
| | (In millions) | | |
| ATSI | $213 | $207 | $6 |
| TrAIL[1] | 200 | 170 | 30 |
| PATH[1] | 18 | 14 | 4 |
| Utilities[1] | 309 | 269 | 40 |
| Total Revenues | $740 | $660 | $80 |

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

Operating Expenses —

Total operating expenses increased by $28 million principally due to the addition of TrAIL, PATH and the Allegheny Utilities' transmission operating expenses for twelve months in 2012 compared to ten months in 2011, partially offset by reduced regulatory asset amortization due to the completion in May 2011 of ATSI's deferred vegetation management cost recovery.

Other Expense —

Other expense increased by $1 million due to twelve months of TrAIL interest expense in 2012 compared to ten months in 2011.

Competitive Energy Services — 2012 Compared with 2011

Net income decreased by $162 million in 2012, compared to 2011. The decrease in net income was primarily due to a $569 million gain ($358 million net of tax) on the partial sale of FEV's interest in Signal Peak in 2011 partially offset by 2011 impairment charges of $315 million primarily resulting from the decision to deactivate six older coal-fired generating plants. In addition, higher operating expenses were partially offset by increased direct and governmental aggregation sales and the inclusion of two additional months of earnings from the Allegheny companies in 2012.

Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis.

Revenues —

Total revenues decreased by $376 million in 2012, compared to 2011, primarily due to a decline in POLR and structured sales and the sale of RECs. Revenues were also adversely impacted by lower unit prices compared to 2011.These decreases were partially offset by growth in direct, governmental aggregation and mass market sales and the inclusion of the Allegheny companies for twelve months in 2012 compared to ten months in 2011.

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The decrease in total revenues resulted from the following sources:

| Revenues by Type of Service | For the Years Ended December 31, 2012 | 2011 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Pre-merger Companies: | | | |
| Direct | $2,849 | $2,624 | $225 |
| Governmental Aggregation | 1,029 | 1,032 | (3) |
| Mass Market | 352 | 129 | 223 |
| POLR and Structured | 899 | 944 | (45) |
| Wholesale[1] | 516 | 435 | 81 |
| Transmission | 116 | 106 | 10 |
| RECs | 7 | 67 | (60) |
| Other | 145 | 173 | (28) |
| Allegheny companies[2] | 1,607 | 1,627 | (20) |
| Intra-segment eliminations[3] | (876) | (117) | (759) |
| Total Revenues | $6,644 | $7,020 | $(376) |
| | | | |
| Allegheny companies[2] | | | |
| Direct | $85 | $84 | $1 |
| POLR and Structured | 366 | 561 | (195) |
| Wholesale[1] | 1,110 | 900 | 210 |
| Transmission | 45 | 88 | (43) |
| Other | 1 | (6) | 7 |
| Total Revenues | $1,607 | $1,627 | $(20) |

(1) Excludes wholesale revenues classified in Discontinued Operations.
(2) Allegheny results include 12 months in 2012 and 10 months in 2011.
(3) Intra-segment eliminations represent the impact of wholesale netting transactions for FES and AE Supply on an hourly basis, and the elimination of intra-segment sales between the companies.

| MWH Sales by Channel | For the Years Ended December 31, 2012 | 2011 | Increase (Decrease) |
|---|---|---|---|
| | (In thousands) | | |
| Pre-merger Companies: | | | |
| Direct | 53,099 | 46,187 | 15.0 % |
| Governmental Aggregation | 17,287 | 15,786 | 9.5 % |
| Mass Market | 5,212 | 1,936 | 169.2 % |
| POLR and Structured | 16,212 | 15,340 | 5.7 % |
| Wholesale(1) | 96 | 2,916 | (96.7 )% |
| Allegheny companies(2) | 29,697 | 26,379 | 12.6 % |
| Intra-segment eliminations | (17,821 ) | (1,806 ) | 886.8 % |
| Total MWH Sales | 103,782 | 106,738 | (2.8 )% |
| | | | |
| Allegheny companies(2) | | | |
| Direct | 1,429 | 1,390 | 2.8 % |
| POLR | 5,874 | 7,974 | (26.3 )% |
| Structured | 578 | 1,492 | (61.3 )% |
| Wholesale(1) | 21,816 | 15,523 | 40.5 % |
| Total MWH Sales | 29,697 | 26,379 | 12.6 % |

(1) Excludes wholesale sales classified in Discontinued Operations.
(2) Allegheny results include 12 months in 2012 and 10 months in 2011.

The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

| MWH Sales Channel: | Source of Change in Revenues Increase (Decrease) Sales Volumes | Prices | Gain on Settled Contracts | Capacity Revenue | Total |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Direct | $393 | $(168 ) | $— | $— | $225 |
| Governmental Aggregation | 98 | (101 ) | — | — | (3 ) |
| Mass Market | 219 | 4 | — | — | 223 |
| POLR and Structured Sales | 16 | (61 ) | — | — | (45 ) |
| Wholesale(1) | (90 ) | (1 ) | 276 | (104 ) | 81 |

(1) Excludes wholesale sales classified in Discontinued Operations.

The increase in Direct revenues of $225 million resulted from higher sales volumes due to the acquisition of new customers, partially offset by lower unit prices. The decrease in Governmental Aggregation of $3 million resulted from lower unit prices, partially offset from the acquisition of new customers primarily in Illinois. The increase in Mass Market of $223 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.6 million customers in December 2012 as compared to 1.8 million in December 2011.

The decrease in POLR and structured revenues of $45 million was due primarily to lower sales volumes at the Ohio Companies, ME, PN and other non-associated companies. Revenues were also adversely impacted by lower unit prices, which were partially offset by increased structured sales. The decline in POLR sales reflects a continued strategic focus on other sales channels.

Wholesale revenues increased $81 million due to increased gains of $276 million on financially settled contracts, partially offset by $91 million decrease in short-term (net hourly positions) transactions resulting primarily from reduced generation and a $104 million decrease in capacity revenues.

The Allegheny companies had a decrease in POLR and structured revenues of $195 million due to lower sales volumes at associated companies. The decline in POLR sales reflects a continued focus on other sales channels by this segment. Transmission revenues declined $43 million due primarily to lower congestion revenues, partially offset by an increase in wholesale revenues due to the intra-segment sale to FES.

Operating Expenses —

Total operating expenses decreased by $621 million in 2012. Excluding the Allegheny companies, total operating expenses decreased by $525 million in 2012 due to the following:

- Fuel costs increased $92 million primarily due to the absence of cash received in 2011 from the assignment of a substantially below-market, long-term fossil fuel contract to a third party ($123 million) and higher unit prices ($57 million), partially offset by lower volumes consumed ($88 million). Higher unit prices resulted primarily from a $50 million termination charge associated with the retirement of a coal contract that is no longer needed as a result of the plant deactivations. Volumes decreased as a result of the deactivation of fossil generating units, the temporary reduction in operations at the Sammis Plant in September 2012 and an increase in economic purchases of power.
- Purchased power costs decreased $26 million due to lower unit prices ($310 million) and reduced capacity expenses ($116 million), partially offset by higher volumes ($158 million) and losses on settled contract ($235 million). The increase in purchased power volumes primarily relates to the overall increase in direct and governmental aggregation sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units and the temporary reduction in operations at Sammis.
- Fossil operating costs decreased by $38 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned generating unit outages.
- Nuclear operating costs decreased by $13 million due primarily to lower contractor, materials and equipment costs, which were partially offset by higher labor costs. In 2012, there were refueling outages at Davis-Besse and Beaver Valley Units 1 and 2. There were refueling outages at Perry and Beaver Valley Unit 2 during 2011. Total MW days were reduced slightly in 2012 compared to 2011.
- Transmission expenses decreased $74 million due primarily to lower congestion, network and line loss costs, partially offset by higher ancillary costs.
- General taxes increased by $8 million primarily due to an increase in revenue-related taxes, which were partially offset by lower taxes associated with a lower ownership percentage in Signal Peak and lower property taxes.
- Depreciation expense decreased $14 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with credits resulting from a settlement with the DOE regarding storage of spent nuclear fuel.
- Other operating expenses decreased by $145 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($123 million), a $5 million decrease in pensions and OPEB mark-to-market adjustment charges from lower net actuarial losses, and the absence of 2011 expenses for a $54 million excess and obsolete inventory adjustment relating to revised inventory practices adopted in connection with the Allegheny merger. These decreases were partially offset by net increases in other expenses of $37 million associated with the absence of revenue related to coal sales due to a lower ownership percentage in Signal Peak, and labor and agent fees associated with the retail business.
- Impairments of long-lived assets decreased $315 million due to the decision to deactivate six unregulated, coal-fired generating plants in 2011.

The Allegheny companies' operations for twelve months in 2012 and ten months in 2011 added $1,486 million and $1,582 million to operating expenses, respectively, as shown in the following table:

| Operating Expenses - Allegheny[1] | For the Years Ended December 31, 2012 | 2011 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Fuel | $861 | $794 | $67 |
| Purchased power | 103 | 149 | (46) |
| Fossil generation | 149 | 148 | 1 |
| Transmission | 123 | 198 | (75) |
| Other operating expenses | 38 | 100 | (62) |
| Pensions and OPEB mark-to-market adjustment | 49 | 44 | 5 |
| General taxes | 41 | 39 | 2 |
| Depreciation | 122 | 110 | 12 |
| Total Operating Expense | $1,486 | $1,582 | $(96) |

[1] Allegheny results include 12 months in 2012 and 10 months in 2011, and excludes items classified in Discontinued Operations.

Fuel expenses increased due to higher generation levels and fuel prices. The purchased power expense decreased due to lower volumes purchased and lower capacity expenses. Transmission expense declined as a result of lower congestion.

Other Expense —

Total other expense in 2012 increased $541 million compared to 2011 due to the absence of the gain on the partial sale of FEV's interest in Signal Peak in 2011 ($569 million), partially offset by reduced net interest expense ($18 million) from debt reductions in 2011 and higher investment income ($10 million) from the NDTs.

Other — 2012 Compared with 2011

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 $37 million decrease in earnings available to FirstEnergy Corp. in 2012 compared to 2011. The decrease resulted primarily from lower other operating expenses ($95 million) due to lower merger-related costs. These benefits were offset by decreased investment income ($33 million), decreased income attributable to noncontrolling interest ($17 million) relating to Signal Peak, which was deconsolidated in the fourth quarter of 2011, and increased income tax expense ($83 million).

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of December 31, 2013 and December 31, 2012, and the changes during the year ended December 31, 2013:

| Regulatory Assets by Source | December 31, 2013 | December 31, 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Regulatory transition costs | $266 | $293 | $(27) |
| Customer receivables for future income taxes | 518 | 505 | 13 |
| Nuclear decommissioning and spent fuel disposal costs | (198) | (219) | 21 |
| Asset removal costs | (362) | (372) | 10 |

| | | | |
|---|---|---|---|
| Deferred transmission costs | 112 | 352 | (240) |
| Deferred generation costs | 346 | 379 | (33) |
| Deferred distribution costs | 194 | 231 | (37) |
| Contract valuations | 260 | 463 | (203) |
| Storm-related costs | 455 | 469 | (14) |
| Other | 263 | 229 | 34 |
| Total | $1,854 | $2,330 | $(476) |

Regulatory assets that do not earn a current return totaled approximately $477 million as of December 31, 2013 primarily related to storm damage costs.

As of December 31, 2013 and December 31, 2012, FirstEnergy had approximately $440 million and $480 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy’s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2014 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

As discussed in the Overview, FirstEnergy's 2013 financial plan also included a series of actions, including the net transfer of 1,476 MW between AE Supply and MP of the Harrison and Pleasants power plants, which closed on October 9, 2013, and the sale of 527 MWs of unregulated hydro assets which closed on February 12, 2014. Proceeds from Harrison and the hydro sale were used to reduce debt at the Competitive Energy Services segment and at FE.

On September 25, 2013, FE filed a registration statement with the SEC to register 4 million shares of common stock to be issued to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan. In addition, during December 2013, FE began fulfilling certain share-based benefit plan obligations through the issuance of authorized but unissued common stock.

In January 2014, FirstEnergy’s Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2014, to shareholders of record at the close of business on February 7, 2014. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008.

Capital expenditures for 2014 are expected to be approximately $3.3 billion, an increase of $1 billion from 2013 primarily due to increased transmission investments. Over the next several years, these capital expenditures, including this transmission expansion program, are expected to be funded with a combination of debt, equity issuances through the stock investment and employee benefit plans, and the projected $320 million annually in cash preserved as a result of the dividend action taken in January 2014. The Utilities and FirstEnergy's competitive generation operations expect to fund their capital expenditures over the next several years through cash from operations, debt, and, depending on the operating company, equity contributions from FE. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to refinance short-term and maturing debt in the ordinary course, subject to market and other conditions. These actions are expected to continue the focus, in 2014, of maintaining strong balance sheets at the Utilities and the Competitive Energy Services segment.

A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy’s liquidity position and ability to fund its capital requirements. To mitigate risk, FirstEnergy’s business strategy stresses financial discipline and a strong focus on execution. Major elements include the expectation of: adequate cash from operations, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital expenditure program, adequately funded pension plan, minimal near-term maturities of existing long-term debt and a commitment to our dividend.

As of December 31, 2013, FirstEnergy’s net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of December 31, 2013, included the following:

| Currently Payable Long-Term Debt | (In millions) |
|---|---|
| PCRBs supported by bank LOCs [1] | $809 |
| FMBs | 175 |
| Unsecured notes | 150 |
| Unsecured PCRBs [1] | 76 |
| Collateralized lease obligation bonds | 74 |
| Sinking fund requirements | 124 |
| Other notes | 7 |
| | $1,415 |

(1) These PCRBs are classified as currently payable long-term debt because the applicable interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings

FirstEnergy had $3,404 million and $1,969 million of short-term borrowings as of December 31, 2013 and December 31, 2012, respectively. FirstEnergy’s available liquidity as of January 31, 2014, was as follows:

| Borrower(s) | Type | Maturity | Commitment | Available Liquidity |
|---|---|---|---|---|
| | | | (In millions) | |
| FirstEnergy(1) | Revolving | May 2018 | $2,500 | $224 |
| FES / AE Supply | Revolving | May 2018 | 2,500 | 2,489 |
| FET(2) | Revolving | May 2018 | 1,000 | — |
| | | Subtotal | $6,000 | $2,713 |
| | | Cash | — | 48 |
| | | Total | $6,000 | $2,761 |

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). The Facilities consist of a $2.5 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities, as amended) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On October 31, 2013, FE amended its existing $2.5 billion multi-year syndicated revolving credit facility to exclude certain after-tax, non-cash write-downs and non-cash charges of approximately $1.4 billion (primarily related to Pension and OPEB mark-to-market adjustments, impairment of long-lived assets and regulatory charges) from the debt to total capitalization ratio calculations incurred through September 30, 2013. Additionally, the amendment provides for a future allowance of approximately $1.35 billion for after-tax, non-cash write-downs and non-cash charges over the remaining life of the facility. Similarly, the FES/AE Supply $2.5 billion revolving credit facility was also amended to exclude certain similar after-tax, non-cash write-downs and non-cash charges of $785.7 million incurred through September 30, 2013 from the debt to total capitalization ratio calculations. As of December 31, 2013, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, 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, 2013:

| Borrower | FirstEnergy Revolving Credit Facility Sub-Limit | FES/AE Supply Revolving Credit Facility Sub-Limit | FET Revolving Credit Facility Sub-Limit | Regulatory and Other Short-Term Debt Limitations | |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| FE | $2,500 | $— | $— | $— | (1) |
| FES | — | 1,500 | — | — | (2) |
| AE Supply | — | 1,000 | — | — | (2) |
| FET | — | — | 1,000 | — | (1) |
| OE | 500 | — | — | 500 | (3) |
| CEI | 500 | — | — | 500 | (3) |
| TE | 500 | — | — | 500 | (3) |
| JCP&L | 600 | — | — | 850 | (3) |
| ME | 300 | — | — | 500 | (3) |
| PN | 300 | — | — | 300 | (3) |
| WP | 200 | — | — | 200 | (3) |
| MP | 150 | — | — | 500 | (3) |
| PE | 150 | — | — | 150 | (3) |
| ATSI | — | — | 100 | 500 | (3) |
| Penn | 50 | — | — | 50 | (3) |
| TrAIL | — | — | 200 | 400 | (3) |

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy Facility and $225 million of the FET Facility, subject to each borrower’s sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower’s borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in “pricing grids,” whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

Term Loan

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

FirstEnergy Money Pools

FirstEnergy’s utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy’s unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2013 was 0.67% per annum for the regulated companies’ money pool and 1.34% per annum for the unregulated companies’ money pool.

Pollution Control Revenue Bonds

As of December 31, 2013, FirstEnergy's currently payable long-term debt included approximately $809 million ($736 million applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of December 31, 2013 were issued by the following banks:

| Bank | Aggregate Amount[1] | Termination Date | Reimbursements of Draws Due |
|---|---|---|---|
| | (In millions) | | |
| UBS | $268 | April 2014 | April 2014 |
| CitiBank N.A. | 164 | June 2014 | June 2014 |
| Wells Fargo | 151 | March 2014 | March 2014 |
| The Bank of Nova Scotia | 48 | April 2014 | April 2014 |
| The Bank of Nova Scotia | 82 | April 2015 | April 2015 |
| The Bank of Nova Scotia | 96 | December 2015 | December 2015 |
| Total | $809 | | |

(1) Excludes approximately $9 million of applicable interest coverage.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of December 31, 2013:

| | Senior Secured | | | Senior Unsecured | | |
|---|---|---|---|---|---|---|
| Issuer | S&P | Moody's | Fitch | S&P | Moody's | Fitch |
| FE | — | — | — | BB+ | Baa3 | BB+ |
| FES | — | — | — | BBB- | Baa3 | BB+ |
| AE Supply | — | — | — | BBB- | Baa3 | BB+ |
| AGC | — | — | — | BBB- | Baa3 | BBB |
| ATSI | — | — | — | BBB- | Baa2 | BBB+ |
| CEI | BBB+ | Baa1 | BBB | BBB- | Baa3 | BBB- |
| JCP&L | — | — | — | BBB- | Baa2 | BBB |
| ME | — | — | — | BBB- | Baa2 | BBB+ |
| MP | BBB+ | Baa1 | A- | — | — | — |
| OE | BBB+ | A3 | BBB+ | BBB- | Baa2 | BBB |
| PN | — | — | — | BBB- | Baa2 | BBB |
| Penn | BBB+ | A3 | BBB+ | — | — | — |
| PE | BBB+ | Baa1 | A- | — | — | — |
| TE | BBB | Baa1 | BBB | — | — | — |
| TrAIL | — | — | — | BBB- | Baa1 | BBB+ |
| WP | BBB+ | A3 | A- | — | — | — |

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of December 31, 2013, FE and its subsidiaries could issue additional debt of approximately $5.3 billion and remain within the limitations of the financial covenants required by the Facilities (as amended). As of December 31, 2013, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $5.3 billion given FE's consolidated debt to total capitalization ratio under its Facility, as amended.

Changes in Cash Position

As of December 31, 2013, FirstEnergy had $218 million of cash and cash equivalents compared to $172 million of cash and cash equivalents as of December 31, 2012. As of December 31, 2013 and December 31, 2012, FirstEnergy had approximately $103 million and $62 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $2,662 million during 2013, $2,320 million during 2012 and $3,063 million during 2011, as summarized in the following table:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| Operating Cash Flows | 2013 | 2012 | 2011 |
| | (In millions) | | |
| Net income | $392 | $771 | $869 |
| Non-cash charges | 2,635 | 2,058 | 2,306 |
| Pension trust contributions | — | (600) | (372) |
| Working capital and other | (365) | 91 | 260 |
| | $2,662 | $2,320 | $3,063 |

The $342 million increase in cash from operations is primarily a result of a $600 million pension contribution in 2012 that did not occur in 2013. The increase was partially offset primarily as a result of payments in 2013 associated with 2012 storm restoration activities.

The $577 million increase in non-cash charges is primarily due to the following:

- $795 million increase from impairment of long-lived assets due to the Hatfield's Ferry and Mitchell plant deactivations as well as the West Virginia asset transfer.
- $132 million increase from the loss on debt redemptions associated with the completion of the FES/AE Supply tender offers and FES debt redemptions described below.
- $162 million increase from lower deferred purchased power and other costs primarily due to the expiration of certain NUG agreements.
- $50 million increase from higher deferred rents and market lease valuation as a result of increased net amortization of lease expense.
- $232 million increase in amortization of regulatory assets primarily due to a regulatory asset impairments associated with the recovery of marginal transmission losses at ME and PN ($254 million), recovery of RECs for the Ohio Companies' ($51 million), and the asset transfer between MP and AE Supply ($23 million) as well as higher default generation service cost recovery in Pennsylvania, partially offset by a reduction of NUG cost recovery at ME and PN and higher transmission cost deferrals in Ohio.
- $99 million increase due to net commodity derivative transactions.
- $404 million decrease in deferred income taxes and investment tax credits. Of the decrease, $156 million was the result of the reversal of deferred income tax liabilities associated with the impairment of Hatfield's Ferry and Mitchell.
- $375 million increase due to storm deferrals related to Hurricane Sandy in 2012.
- $865 million decrease due to Pensions and OPEB mark-to-market charges, reflecting a higher discount rate to measure related obligations in 2013.

The $456 million decrease in cash flows from working capital and other is primarily due to the following:

- $101 million decrease from increased customer receivables during 2013 primarily as a result of increased weather related usage as described in the Results of Operations above.
- $183 million of decreased asset removal costs charged to income primarily related to hurricane Sandy in 2012.
- $146 million increase from materials and supplies, primarily due to reduced fuel inventory resulting primarily from plant deactivations in 2013 and 2012.
- $125 million decrease from lower accounts payable balances at the end of 2013, primarily due to higher balances related to Hurricane Sandy in 2012, a portion of which was paid in 2013.
- $187 million decrease from make whole premiums paid on debt redemptions during 2013.
- $114 million decrease from increased prepaid taxes.
- $87 million increase from higher accrued taxes driven by the timing of state tax related liabilities.

Cash Flows From Financing Activities

In 2013, cash provided from financing activities was $477 million compared to $807 million of net cash provided from financing activities during 2012. The following table summarizes new debt financing (net of any discounts) and redemptions:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| Securities Issued or Redeemed / Repaid | 2013 | 2012 | 2011 |
| | (In millions) | | |
| New Issues | | | |
| PCRBs | $— | $650 | $272 |
| Long-term revolving credit | — | — | 70 |
| Senior secured notes | 445 | — | — |
| FMBs | 1,000 | 100 | — |
| Unsecured Notes | 2,300 | — | 262 |
| | $3,745 | $750 | $604 |
| | | | |
| Redemptions / Repayments | | | |
| PCRBs | $(470) | $(238) | $(792) |
| Long-term revolving credit | (50) | — | (495) |
| Senior secured notes | (376) | (118) | (460) |
| FMBs | (420) | — | (15) |
| Unsecured notes | (2,284) | (584) | (147) |
| | $(3,600) | $(940) | $(1,909) |
| | | | |
| Tender premiums paid on debt redemptions | $(110) | $— | $— |
| | | | |
| Short-term borrowings, net | $1,435 | $1,969 | $(700) |

On March 5, 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their concurrent tender offers.

On March 28, 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. The $369 million of FES repurchases consisted of original maturities of $252 million due 2021 and $117 million due 2039. The $294 million of AE Supply repurchases consisted of original maturities of $194 million due 2019 and $100 million due 2039. FES and AE Supply paid $67 million and $43 million, respectively, in tender premiums to repurchase the tendered senior notes. FirstEnergy recorded a loss on debt redemption of $119 million (FES - $71 million), including such premiums and other related expenses. The tender premiums paid are included in cash flows from financing activities in the Consolidated Statement of Cash Flows.

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME 4.95% senior unsecured notes that matured in March 2013 and short-term borrowings.

On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of make-whole premiums paid. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

During August, the Ohio Companies redeemed an additional $660 million of long-term debt with interest rates ranging from 5.65% to 7.25% and paid approximately $120 million of make-whole premiums which were deferred as a regulatory asset and will be amortized over the original life of the redeemed debt. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows. Additionally, during August, JCP&L issued $500 million of 4.7% unsecured notes due April 2024 and used the proceeds to pay down a portion of its short-term debt obligations.

As discussed in Note 8, Variable Interest Entities, in June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million of redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On November 15, 2013, AE Supply optionally redeemed $235 million of its 7.00% PCRBs due July 15, 2039 at 100% of the principal amount in connection with the deactivation of operations at Hatfield's Ferry.

On November 27, 2013, MP issued $400 million of 4.10% FMBs due April 15, 2024 and $600 million of 5.40% FMBs due December 15, 2043. Proceeds from this offering were used by MP to: (i) repay at maturity $300 million of its FMBs, 7.95% Series due December 15, 2013; (ii) redeem $120 million of its FMBs, 6.70% Series due June 15, 2014; (iii) repay a $572.7 million short-term promissory note originally issued on October 9, 2013 to its affiliate, AE Supply in connection with MP’s acquisition of the remaining ownership of the Harrison Power Station; and (iv) for working capital needs and other general corporate purposes.

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million. On December 26, 2013, PN redeemed $150 million of its 5.13% Senior Notes due April 1,2014 and ME redeemed $100 million of its 4.88% Senior Notes due April 1, 2014.

Cash Flows From Investing Activities

Cash used for investing activities in 2013 principally represented cash used for property additions. The following table summarizes investing activities for 2013, 2012 and 2011:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| Cash Used for Investing Activities | 2013 | 2012 | 2011 |
| | (In millions) | | |
| Property Additions: | | | |
| Regulated distribution | $1,272 | $1,074 | $868 |
| Regulated transmission | 461 | 507 | 390 |
| Competitive energy services | 827 | 1,014 | 778 |
| Other and reconciling adjustments | 78 | 83 | 93 |
| Nuclear fuel | 250 | 286 | 149 |
| Cash received from Allegheny merger | — | — | (590) |
| Proceeds from asset sales | (4) | (17) | (840) |
| Investments | 72 | (62) | 42 |
| Asset removal costs | 146 | 229 | 114 |
| Other | (9) | 43 | (48) |
| | $3,093 | $3,157 | $956 |

Net cash used for investing activities during 2013 decreased by $64 million compared to 2012. The decrease was principally due to a decrease in property additions of $40 million, lower asset removal costs and nuclear fuel, partially offset by an increase in net purchases of investment securities and lower cash investments.

In 2012, FG acquired certain equity and other lessor interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $262 million and in March of 2013, FG acquired the remaining interests for approximately $221 million. During 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million. Additionally, in February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million.

CONTRACTUAL OBLIGATIONS

As of December 31, 2013, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

| Contractual Obligations | Total | 2014 | 2015-2016 | 2017-2018 | Thereafter |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Long-term debt[1] | $17,005 | $1,376 | $2,305 | $3,094 | $10,230 |
| Short-term borrowings | 3,404 | 3,404 | — | — | — |
| Interest on long-term debt[2] | 10,965 | 881 | 1,658 | 1,424 | 7,002 |
| Operating leases[3] | 2,422 | 202 | 405 | 251 | 1,564 |
| Fuel and purchased power[4] | 22,292 | 2,485 | 4,111 | 2,971 | 12,725 |
| Capital expenditures | 2,516 | 1,099 | 775 | 453 | 189 |
| Pension funding | 1,087 | — | 717 | 229 | 141 |
| Other[5] | 279 | 75 | 82 | 65 | 57 |
| Total | $59,970 | $9,522 | $10,053 | $8,487 | $31,908 |

(1) Excludes unamortized discounts and premiums, fair value accounting adjustments and capital leases.
(2) Interest on variable-rate debt based on rates as of December 31, 2013.
(3) See Note 6, Leases, of the Combined Notes to Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(5) Includes amounts for capital leases (see Note 6, Leases, of the Combined Notes to Consolidated Financial Statements) and contingent tax liabilities (see Note 5, Taxes, of the Combined Notes to Consolidated Financial Statements).

Excluded from the data shown above are estimates for the cash outlays from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. Although actual amounts will be determined by future customer behavior and consumption levels, management currently estimates these cash outlays will be approximately $2.9 billion in 2014, $0.7 billion of which are expected to relate to the Utilities' contracts with FES.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could be required to make under these guarantees as of December 31, 2013, was approximately $4.3 billion, as summarized below:

| Guarantees and Other Assurances | Maximum Exposure (In millions) |
| --- | --- |
| FirstEnergy Guarantees on Behalf of its Subsidiaries | |
| Energy and Energy-Related Contracts[(1)] | $269 |
| LOC (long-term debt) - interest coverage[(2)] | 5 |
| OVEC obligations | 300 |
| Deferred compensation arrangements | 478 |
| Other[(3)] | 323 |
| | 1,375 |
| Subsidiaries' Guarantees | |
| Energy and Energy-Related Contracts | 66 |
| LOC (long-term debt) - interest coverage[(2)] | 3 |
| FES' guarantee of NG's nuclear property insurance | 88 |
| FES' guarantee of FG's sale and leaseback obligations | 2,030 |
| Other | 10 |
| | 2,197 |
| | |
| Global Holding facility | 350 |
| Surety Bonds | 264 |
| LOCs[(4)] | 128 |
| | 742 |
| Total Guarantees and Other Assurances | $4,314 |

(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 $809 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Primarily includes guarantees of $125 million and $11 million for nuclear decommissioning funding assurances and $161 million supporting OE's sale and leaseback arrangement, and $20 million for railcar leases.

(4) Includes $7 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $96 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $25 million pledged in connection with the sale and leaseback of Perry by OE.

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

Collateral and Contingent-Related Features

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2013, FES has posted collateral of $142 million and AE supply has posted collateral of $8 million. The Regulated Distribution segment has posted collateral of $11 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2013:

| Collateral Provisions | FES (In millions) | AE Supply | Utilities | Total |
|---|---|---|---|---|
| Split Rating (One rating agency's rating below investment grade) | $496 | $6 | $53 | $555 |
| BB+/Ba1 Credit Ratings | $542 | $6 | $53 | $601 |
| Full impact of credit contingent contractual obligations | $777 | $58 | $88 | $923 |

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and Competitive Energy Services segment. As of December 31, 2013, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $66 million and $2 million, respectively.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the new facility.

In connection with the current facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the current facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility no later than July 20, 2015, which reflects the terms of an amendment dated August 14, 2013, on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1, 2013 through October 18, 2015, which amends the rate in the prior agreement, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Plant sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was approximately $1.1 billion as of December 31, 2013, of which approximately $1 billion relates to the 2007 Bruce Mansfield sale and leaseback arrangement expiring in 2040, and approximately $75 million relates to the Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback arrangements expiring in 2016 and 2017, respectively. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

During the second quarter of 2013, in connection with the Perry sale and leaseback arrangement, OE provided notice to return the leased interests in the plant to the owner participants (representing an aggregate of approximately 103 MWs of the 1,268 MWs of total capacity of the Perry Plant) at the expiration of the lease (May 2016) in lieu of extending the lease or buying the interest at the then appraised FMV. During 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million. Additionally, in February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million.

## MARKET RISK INFORMATION

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

### Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative contracts assets and liabilities as of December 31, 2013 are summarized by year in the following table:

| Source of Information-Fair Value by Contract Year | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| | (In millions) | | | | | | |
| Prices actively quoted[1] | $(6) | $— | $— | $— | $— | $— | $(6) |
| Other external sources[2] | (12) | (32) | (21) | (10) | — | — | (75) |
| Prices based on models | (5) | — | 1 | 1 | (9) | (15) | (27) |
| Total[3] | $(23) | $(32) | $(20) | $(9) | $(9) | $(15) | $(108) |

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(202) million in non-hedge derivative contracts that are primarily related to NUG contracts. NUG contracts are generally subject to regulatory accounting and do not materially impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2013, a 10% adverse change in commodity prices would decrease net income by approximately $27 million during the next 12 months.

Equity Price Risk

As of December 31, 2013, the FirstEnergy pension plan assets were approximately allocated as follows: 18% in equity securities, 40% in fixed income securities, 23% in absolute return strategies, 6% in real estate and 13% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2013, FirstEnergy made no contributions to its qualified pension plans. See Note 3, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2013, FirstEnergy's pension plan assets lost approximately (1.0)% as compared to an expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2013, approximately 77% of the funds were invested in fixed income securities, 15% of the funds were invested in equity securities and 8% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,695 million, $316 million and $179 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2013, excluding $11 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $32 million reduction in fair value as of December 31, 2013. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2013, FirstEnergy contributed approximately $5 million to the NDT.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6, Leases of the Combined Notes to Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

| Year of Maturity | 2014 | 2015 | 2016 | 2017 | 2018 | There-after | Total | Fair Value |
|---|---|---|---|---|---|---|---|---|
| | (In millions) | | | | | | | |
| Assets: | | | | | | | | |
| Investments Other Than Cash and Cash Equivalents: | | | | | | | | |
| Fixed Income | $16 | $10 | $5 | $2 | | $1,914 | $1,947 | $1,949 |
| Average interest rate | 8.7 % | 8.8 % | 8.9 % | 8.8 % | | 4.8 % | 4.9 % | |
| Liabilities: | | | | | | | | |
| Long-term Debt: | | | | | | | | |
| Fixed rate | $566 | $817 | $668 | $1,516 | $679 | $10,344 | $14,590 | $15,555 |
| Average interest rate | 4.9 % | 4.5 % | 5.5 % | 6.1 % | 6.8 % | 5.7 % | 5.7 % | |
| Variable rate | | $150 | | | $656 | $1,653 | $2,459 | $2,402 |
| Average interest rate | | 1.7 % | | | 2.7 % | 2.2 % | 2.3 % | |

In 2013, in connection with certain debt redemptions, FirstEnergy recorded gains of approximately $17 million related to terminated interest rate swaps. In 2012, FirstEnergy terminated all forward starting swap agreements resulting in cash proceeds and a net gain, recorded as a reduction to interest expense, of approximately $6 million. As of December 31, 2013 and 2012, FirstEnergy had no forward starting swap agreements.

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of offset. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FirstEnergy's portfolio of energy contracts has a current weighted average risk rating for energy contract counterparties of BBB (S&P).

Retail Credit Risk

FirstEnergy's principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

OUTLOOK

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

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

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by May 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers.

All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On November 15, 2013, the Division of Rate Counsel filed testimony recommending that approximately $15 million of JCP&L's costs be disallowed for recovery. Evidentiary hearings in this proceeding were scheduled for January 2014 but were subsequently adjourned by the NJBPU before their commencement. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on February 24, 2014.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Ohio Companies recently reported that they met all of their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff’s recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. Hearings on the plans are scheduled to be held March 4-7, 2014. The Pennsylvania Companies expect a decision from the PPUC by August 4, 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC’s motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013.

On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court’s decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further

benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ’s decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The Office of Consumer Advocate took exception to one issue and both parties filed replies to exceptions on December 12, 2013. The case is now before the PPUC for consideration.
A decision is expected during the first quarter of 2014.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed but the WVPSC has not yet issued an opinion in this matter.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. The charge is included in Impairment of long lived assets within the Consolidated Statement of Income. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. In accordance with the settlement, MP and PE will file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the West Virginia Supreme Court. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. Oral argument before the Supreme Court is scheduled for March 5, 2014.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision 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 (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated for briefing and disposition before that court. Briefing is complete, and the case will be scheduled for oral argument, with a decision currently expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's separate Order No. 1000 compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, have sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing was completed in December 2013 and oral argument is scheduled for March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility of certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone for the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs to the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In the May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. The case thereafter was briefed and oral arguments took place on December 11, 2013. A decision currently is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy’s subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. See Note 20, Discontinued Operations and Assets Held for Sale for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, in January 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the “joint and common market” stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $65.5 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed

PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FES and AE Supply's request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into three categories: (i) Demand Response (DR); (ii) imports; and (iii) modeling of transmission upgrades in calculating geographic clearing prices. The purpose of PJM’s tariff amendments is to ensure that resources that clear in the RPM auctions are available and able to satisfy all obligations under the PJM tariffs. In each of the affected dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC issued deficiency letters requesting additional information from PJM regarding the imports and modeling filings, and on January 30, 2014 accepted the DR filing as proposed. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling and imports filings. PJM's compliance filings and all other filings in the dockets are pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

ENVIRONMENTAL MATTERS

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

CAA Compliance

FirstEnergy is required to meet federally-approved $SO_2$ and NOx emissions regulations under the CAA. FirstEnergy complies with $SO_2$ and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties.

In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which affirmed the dismissal on August 21, 2013 and then denied petitions for rehearing on December 12, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, and the Allegheny Utilities finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and $SO_2$ emissions in two phases (2009/2010 and 2015), ultimately capping $SO_2$ emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but 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 decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and $SO_2$ emissions in two phases (2012 and 2014), ultimately capping $SO_2$ emissions in affected states to 2.4

million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and $SO_2$ emission allowances between power plants located in the same state and interstate trading of NOx and $SO_2$ emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the D.C. Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR and heard oral argument on December 10, 2013. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS has been challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. Oral arguments were heard on December 10, 2013. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payments of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including the EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of $CO_2$ equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard of 1,000 lbs. $CO_2$/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. $CO_2$/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. $CO_2$/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including $CO_2$, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including

Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting $CO_2$ emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The $CO_2$ emissions per KWH of electricity generated by FirstEnergy is lower than many of its 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 CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. The period for finalizing the Section 316(b) regulation was extended to April 17, 2014 under a Settlement Agreement between EPA and certain NGOs. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its asset retirement obligation for LBR by $163 million in 2013. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean

Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2013 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $128 million have been accrued through December 31, 2013. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2013, FirstEnergy had approximately $2.2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. FE maintains a $125 million parental guaranty relating to a potential shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. FE also maintains an $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate.

On October 4, 2013, during a refueling outage for Beaver Valley Unit 1, FENOC conducted a planned visual examination of the interior containment liner and coatings. The containment design for Beaver Valley includes an interior steel liner that is surrounded by reinforced concrete. A penetration through the containment steel liner plate of approximately 0.4 inches by 0.28 inches was discovered. A detailed investigation was initiated, including laboratory analysis that has indicated that the degraded area was initiated by foreign material inadvertently left in the concrete during construction. An assessment has been performed which concluded that any postulated leakage through the affected area was within overall allowable limits for the containment building. The structural integrity of the containment building is not affected. Repair of the containment liner was completed and Unit 1 was returned to service on November 4, 2013.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft Generic Environmental Impact Statement and published a proposed rule on this subject in September of 2013. Other contentions proposed by the petitioners in this proceeding have been rejected by the ASLB. On February 18, 2014, Beyond Nuclear and Don't Waste Michigan, two of the petitioners in the Davis-Besse license renewal proceeding, requested that the NRC institute a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On February 27, 2014, these petitioners requested a suspension of the licensing decision in the Davis-Besse license renewal proceeding to allow the NRC to complete this rulemaking.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirm that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On February 1, 2014, the Davis-Besse Nuclear Power Station entered into an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall will be repaired during this outage to conform to its original design configuration. This condition is not expected to extend the outage.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only and is currently in the discovery phase. A hearing is scheduled for May 13-14, 2014.

Other Legal Matters

In 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death and negligence after his wife was fatally electrocuted when she contacted a downed power line. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty, which settlement is subject to PPUC approval. On August 29, 2013, the PPUC entered an Order granting the Goretzka family limited party status for the sole purpose of submitting comments to the settlement and issuing the settlement for comment by the parties. On September 16, 2013, the Goretzka family filed Limited Objections to the settlement. Reply comments were filed by WP on September 30, 2013. The PPUC entered an Opinion and Order on January 9, 2014 approving the Settlement with limited modifications regarding the frequency of refresher training and reporting obligations. WP filed a letter on January 17, 2014 accepting those modifications and noting its intent to begin implementation of the settlement terms.

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 loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 15, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. FirstEnergy's accounting policies require significant judgment regarding estimates and assumptions underlying the amounts included in the financial statements. Additional information regarding the application of accounting policies is included in the Combined Notes to Consolidated Financial Statements.

### Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class. See Note 1, Organization and Basis of Presentation for additional details.

### Regulatory Accounting

FirstEnergy’s regulated distribution and regulated transmission segments are subject to regulations that set the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to be recovered. 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 and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. See Note 15, Regulatory Matters for additional information.

### Pensions and OPEB Accounting

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover 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 provides some non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits and/or subsidies to purchase health insurance, which include certain employee contributions, deductibles and co-payments, may also be available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy’s pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2013, FirstEnergy did not make any contributions to its qualified pension plan. The underfunded status of FirstEnergy’s qualified and non-qualified pension and OPEB plans as of December 31, 2013 was $2.5 billion.

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 OPEB obligations. The assumed discount rates for pensions were 5.00%, 4.25% and 5.00% as of December 31, 2013, 2012 and 2011, respectively. The assumed discount rates for OPEB were 4.75%, 4.00% and 4.75% as of December 31, 2013, 2012 and 2011, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2013, FirstEnergy's qualified pensions and OPEB plan assets lost $(22) million or (0.3)% compared to amounts earned of $660 million, or 9.2% in 2012. The qualified pension and OPEB costs in 2013 and 2012 were computed using an assumed 7.75% rate of return for both years on plan assets which generated $535 million and $523 million of expected returns on plan assets, respectively. The expected return on pensions 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 will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

Based on discount rates of 5.00% for pension, 4.75% for OPEB and an estimated return on assets of 7.75%, FirstEnergy expects its 2014 pre-tax net periodic postemployment benefit credits (including amounts capitalized) to be approximately $48 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2014). The following table reflects the portion of pensions and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2013.

| Postemployment Benefits Expense (Credits) | 2013 | 2012 | 2011 |
|---|---|---|---|
| | (In millions) | | |
| Pensions | $(134) | $596 | $555 |
| OPEB | (196) | (34) | (112) |
| Total | $(330) | $562 | $443 |

Health care cost trends continue to increase and will affect future OPEB costs. The 2013 composite health care trend rate assumptions were approximately 7.25-7.75%, compared to 7.5-8.0% in 2012, gradually decreasing to 5% in later years. In determining FirstEnergy’s trend rate assumptions, included are the specific provisions of FirstEnergy’s health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy’s health care plans, and projections of future medical trend rates. The effect on the pension and OPEB costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

| Assumption | Adverse Change | Pensions | OPEB | Total |
|---|---|---|---|---|
| | | | (In millions) | |
| Discount rate | Decrease by .25% | 250 | 19 | $269 |
| Long-term return on assets | Decrease by .25% | 15 | 1 | $16 |
| Health care trend rate | Increase by 1.0% | N/A | 24 | $24 |

Please see Note 3, Pensions and Other Postemployment Benefits for additional information

Long-Lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. See Note 11, Impairment of Long-Lived Assets for additional information.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset. ARO's as of December 31, 2013, are described further in Note 14, Asset Retirement Obligations.

Income Taxes

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

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Company recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. See Note 5, Taxes for additional information.

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. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission segments as of July 31, 2013, and determined the fair values of these segments were, more likely than not, greater than their carrying values. Due to excess generation supply in the region, which has caused a period of protracted low power and capacity prices impacting Competitive operations, FirstEnergy performed a quantitative assessment of the Competitive Energy Services segment as of July 31, 2013. The fair value of the Competitive Energy Services segment was calculated using a discounted cash flow analysis which was dependent on subjective factors determined by FirstEnergy management. Assumptions used in the analysis include discount rates, future power and natural gas prices, projected operating and capital cash flows and the fair value of debt. The estimated fair value of the Competitive Energy Services segment exceeded its carrying amount (including goodwill) as of July 31, 2013. Estimates of future cash flows are based upon relevant data at a point in time, which are subject to change and could vary from actual results. Continued weak economic conditions, lower than forecasted power and capacity prices, and revised environmental requirements could have a negative impact on future goodwill assessments.

See Note 1, Organization and Basis of Presentation for additional details.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FE. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding the Allegheny facilities), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs. On February 12, 2014, FES sold its hydroelectric generation facility to LS Power. FES expects to record a pre-tax gain of $177 million associated with the sale in the first quarter of 2014.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States.

FES is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. FES attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

During the second quarter of 2013, FE completed a $1.5 billion equity contribution to FES.

For additional information with respect to FES, please see the information contained in FirstEnergy's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Overview, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Net income decreased by $127 million in 2013 compared to 2012, as more fully described below.

Revenues -

Total revenues increased $279 million, in 2013, compared to 2012, primarily due to growth in governmental aggregation and mass market sales and an increase in POLR and structured sales, partially offset by a decline in wholesale revenues. Revenues were adversely impacted by lower unit prices compared to 2012 as a result of a significant decrease in market prices beginning in the fourth quarter of 2011 when the 2013 retail sales position was approximately 50% committed.

The increase in total revenues resulted from the following sources:

| Revenues by Type of Service | For the Years Ended December 31, 2013 | 2012 | Increase (Decrease) |
| --- | --- | --- | --- |
| | (In millions) | | |
| Direct | $2,865 | $2,849 | $16 |
| Governmental Aggregation | 1,185 | 1,029 | 156 |
| Mass Market | 448 | 352 | 96 |
| POLR and Structured | 1,159 | 899 | 260 |
| Wholesale[1] | 250 | 516 | (266) |
| Transmission | 121 | 116 | 5 |
| RECs | 2 | 7 | (5) |
| Other | 143 | 126 | 17 |
| Total Revenues | $6,173 | $5,894 | $279 |

[1] Excludes wholesale revenues classified in Discontinued Operations.

| MWH Sales by Channel | For the Years Ended December 31, 2013 | 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In thousands) | | |
| Direct | 55,327 | 53,099 | 4.2 % |
| Governmental Aggregation | 20,859 | 17,287 | 20.7 % |
| Mass Market | 6,761 | 5,212 | 29.7 % |
| POLR and Structured | 23,139 | 16,212 | 42.7 % |
| Wholesale[1] | — | 96 | (100.0 )% |
| Total MWH Sales | 106,086 | 91,906 | 15.4 % |

[1] Excludes wholesale sales classified in Discontinued Operations.

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

| MWH Sales Channel: | Source of Change in Revenues Increase (Decrease) Sales Volumes | Prices | Gain on Settled Contracts | Capacity Revenue | Total |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Direct | $120 | $(104 ) | $— | $— | $16 |
| Governmental Aggregation | 213 | (57 ) | — | — | 156 |
| Mass Market | 105 | (9 ) | — | — | 96 |
| POLR and Structured Sales | 392 | (132 ) | — | — | 260 |
| Wholesale[1] | (2 ) | — | (210 ) | (54 ) | (266 ) |

[1] Excludes wholesale sales classified in Discontinued Operations.

The increase in Direct revenues of $16 million resulted from higher sales volumes due to the acquisition of new larger customers, partially offset by lower unit prices. The increase in Governmental Aggregation of $156 million resulted from the acquisition of new customers primarily in Illinois, partially offset by lower unit prices. The increase in Mass Market of $96 million resulted from the acquisition of new customers primarily in Ohio, Illinois and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of December 31, 2013, as compared to 2.6 million as of December 31, 2012.

The increase in POLR and structured revenues of $260 million was due primarily to increased sales volumes in each channel, partially offset by lower unit prices.

Wholesale revenues decreased $266 million primarily due to lower gains of $210 million on financially settled contracts, a $54 million decrease in capacity revenues resulting primarily from lower capacity prices and $2 million in lower sales volumes.

Transmission revenue increased $5 million due to higher congestion revenue and higher ancillary revenue associated with additional retail load.

Other revenue increased $17 million due primarily to repurchases in 2012 and 2013 of third-party lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses increased by $376 million in 2013 compared to 2012.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2013 compared with 2012:

| Operating Expense | Source of Change Increase (Decrease) Volumes | Prices | Loss on Settled Contracts | Capacity Expense | Total |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Fossil Fuel | $(27) | $(76) | $81 | $— | $(22) |
| Nuclear Fuel | (6) | 3 | — | — | (3) |
| Affiliated Purchased Power | 5 | 2 | 28 | — | 35 |
| Non-affiliated Purchased Power(1) | 621 | 124 | (221) | (78) | 446 |

(1) Excludes purchased power classified in Discontinued Operations.

Fuel costs decreased $25 million primarily due to lower volumes associated with the plants that were deactivated in 2012 and those under RMR arrangements, and lower unit prices associated with new and restructured coal contracts, partially offset by expenses associated with settlements of past damages on transportation contracts. The increase in affiliated purchased power is primarily due to increased losses on financially settled contracts with AE Supply. The increase in non-affiliated purchased power was due to higher volumes associated with the overall increase in retail sales volumes, lower generation and higher on-peak prices.

Other operating expenses increased by $131 million in 2013, compared to 2012 due to the following:

- Fossil operating costs decreased by $15 million due primarily to lower labor costs resulting from previously deactivated units and lower compensation and benefit expenses associated with plan changes.
- Nuclear operating costs decreased by $21 million due primarily to lower compensation and benefit expenses associated with plan changes.
- Transmission expenses increased $102 million due primarily to higher retail load and higher network costs associated with POLR sales in Pennsylvania, partially offset by lower congestion costs as well as credits received in 2013 for previously incurred PJM transmission costs associated with RMR units in the ATSI zone. Effective June 1, 2013, network transmission costs became the responsibility of suppliers of POLR sales in Pennsylvania.
- Other operating expenses increased by $65 million due primarily to an increase in mark-to-market expense on commodity contract positions ($94 million), partially offset by reduced lease expense ($19 million) from repurchasing interests in sale and leaseback transactions during 2012 and 2013.

Pensions and OPEB mark-to-market charges decreased $247 million primarily reflecting a higher discount rate to measure related obligations in 2013.

Depreciation expense increased $34 million primarily due to an increase in depreciable base as a result of capital expenditures, and repurchasing interests in Bruce Mansfield and Beaver Valley Unit 2 sale leasebacks noted above.

Other Expense -

Total other expense increased by $127 million in 2013, compared to 2012, primarily due to a $103 million loss on debt redemptions in connection with senior notes that were repurchased, lower investment income of $50 million due to higher OTTI on NDT investments, partially offset by lower net interest expense of $33 million due to debt redemptions and repurchases.

Market Risk Information

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

Commodity Price Risk

FES is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FES uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

Sources of information for the valuation of commodity derivative contracts assets and liabilities as of December 31, 2013 are summarized by year in the following table:

| Source of Information-Fair Value by Contract Year | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| | (In millions) | | | | | | |
| Prices actively quoted[1] | $(6) | $— | $— | $— | $— | $— | $(6) |
| Other external sources[2] | 65 | 16 | 10 | 10 | — | — | 101 |
| Prices based on models | (5) | — | 1 | 1 | 2 | — | (1) |
| Total | $54 | $16 | $11 | $11 | $2 | $— | $94 |

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.

FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2013, a 10% adverse change in commodity prices would decrease net income by approximately $27 million during the next 12 months.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

| Year of Maturity | 2014 | 2015 | 2016 | 2017 | 2018 | There-after | Total | Fair Value |
|---|---|---|---|---|---|---|---|---|
| | (In millions) | | | | | | | |
| Assets: | | | | | | | | |
| Investments Other Than Cash and Cash Equivalents: | | | | | | | | |
| Fixed Income | | | | | | $935 | $935 | $935 |
| Average interest rate | | | | | | 5.2 % | 5.2 % | |
| Liabilities: | | | | | | | | |
| Long-term Debt: | | | | | | | | |
| Fixed rate | $125 | $78 | $32 | $32 | $141 | $1,857 | $2,265 | $2,337 |
| Average interest rate | 7.6 % | 8.1 % | 8.0 % | 2.9 % | 5.6 % | 4.7 % | 5.1 % | |
| Variable rate | | | | | $6 | $730 | $736 | $736 |
| Average interest rate | | | | | 0.02 % | 0.04 % | 0.04 % | |

Equity Price Risk

NDT funds have been established to satisfy NG's nuclear decommissioning obligations. Included in FES' NDT are fixed income, equities and short-term investments carried at market values of approximately $935 million, $207 million and $125 million, respectively, as of December 31, 2013, excluding $9 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $21 million reduction in fair value as of December 31, 2013. NG recognizes in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FES' NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FES evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FES may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FES monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FES measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FES has a legally enforceable right of offset. FES monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FES aggressively manages the quality of its portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P).

Retail Credit Risk

FES is exposed to retail credit risk through competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FES' retail credit risk may be adversely impacted.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2013 consolidated financial statements as stated in their audit report included herein.

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 five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2013.

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 published in 1992, 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, 2013. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

## MANAGEMENT REPORTS

### Management’s Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company’s 2013 consolidated financial statements as stated in their audit report included herein.

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

FirstEnergy’s Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee’s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company’s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm’s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm’s independence. The Committee also reviews management’s programs to monitor compliance with the Company’s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2013.

### 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 published in 1992, 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, 2013.

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, comprehensive 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework, published in 1992, by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 27, 2014

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows, present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 27, 2014

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

| | For the Years Ended December 31, | | |
|---|---|---|---|
| (In millions, except per share amounts) | 2013 | 2012 | 2011 |
| REVENUES: | | | |
| Electric utilities | $9,479 | $9,800 | $10,573 |
| Unregulated businesses | 5,438 | 5,473 | 5,532 |
| Total revenues* | 14,917 | 15,273 | 16,105 |
| OPERATING EXPENSES: | | | |
| Fuel | 2,496 | 2,471 | 2,317 |
| Purchased power | 3,963 | 4,246 | 4,874 |
| Other operating expenses | 3,593 | 3,760 | 3,949 |
| Pensions and OPEB mark-to-market adjustment | (256) | 609 | 507 |
| Provision for depreciation | 1,202 | 1,119 | 1,062 |
| Deferral of storm costs | — | (375) | (145) |
| Amortization of regulatory assets, net | 539 | 307 | 474 |
| General taxes | 978 | 984 | 977 |
| Impairment of long-lived assets (Note 11) | 795 | — | 413 |
| Total operating expenses | 13,310 | 13,121 | 14,428 |
| OPERATING INCOME | 1,607 | 2,152 | 1,677 |
| OTHER INCOME (EXPENSE): | | | |
| Loss on debt redemptions | (132) | — | — |
| Gain on partial sale of Signal Peak | — | — | 569 |
| Investment income | 36 | 77 | 114 |
| Interest expense | (1,016) | (1,001) | (1,008) |
| Capitalized interest | 75 | 72 | 70 |
| Total other expense | (1,037) | (852) | (255) |
| INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES | 570 | 1,300 | 1,422 |
| INCOME TAXES | 195 | 545 | 566 |
| INCOME FROM CONTINUING OPERATIONS | 375 | 755 | 856 |
| Discontinued operations (net of income taxes of $9, $8 and $8, respectively) (Note 20) | 17 | 16 | 13 |
| NET INCOME | 392 | 771 | 869 |
| Income (loss) attributable to noncontrolling interest | — | 1 | (16) |
| EARNINGS AVAILABLE TO FIRSTENERGY CORP. | $392 | $770 | $885 |

| | | | |
|---|---|---|---|
| EARNINGS PER SHARE OF COMMON STOCK: | | | |
| Basic - Continuing Operations | $0.90 | $1.81 | $2.19 |
| Basic - Discontinued Operations (Note 20) | 0.04 | 0.04 | 0.03 |
| Basic - Earnings Available to FirstEnergy Corp. | $0.94 | $1.85 | $2.22 |
| | | | |
| Diluted - Continuing Operations | $0.90 | $1.80 | $2.18 |
| Diluted - Discontinued Operations (Note 20) | 0.04 | 0.04 | 0.03 |
| Diluted - Earnings Available to FirstEnergy Corp. | $0.94 | $1.84 | $2.21 |
| | | | |
| WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING: | | | |
| Basic | 418 | 418 | 399 |
| Diluted | 419 | 419 | 401 |
| | | | |
| DIVIDENDS DECLARED PER SHARE OF COMMON STOCK | $1.65 | $2.20 | $2.20 |

*Includes excise tax collections of $458 million, $484 million and $511 million in 2013, 2012 and 2011, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | For the Years Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2013 | 2012 | 2011 |
| NET INCOME | $392 | $771 | $869 |
| OTHER COMPREHENSIVE INCOME (LOSS): | | | |
| Pensions and OPEB prior service costs | (160) | (115) | (90) |
| Amortized losses on derivative hedges | 3 | 1 | 23 |
| Change in unrealized gain on available-for-sale securities | (10) | (6) | 19 |
| Other comprehensive loss | (167) | (120) | (48) |
| Income tax benefits on other comprehensive loss | (66) | (79) | (49) |
| Other comprehensive income (loss), net of tax | (101) | (41) | 1 |
| COMPREHENSIVE INCOME | 291 | 730 | 870 |
| Comprehensive income (loss) attributable to noncontrolling interest | — | 1 | (16) |
| COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP. | $291 | $729 | $886 |

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

| (In millions, except share amounts) | December 31, 2013 | December 31, 2012 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $218 | $172 |
| Receivables- | | |
| Customers, net of allowance for uncollectible accounts of $52 in 2013 and $40 in 2012 | 1,720 | 1,614 |
| Other, net of allowance for uncollectible accounts of $3 in 2013 and $4 in 2012 | 198 | 315 |
| Materials and supplies, at average cost | 752 | 861 |
| Prepaid taxes | 226 | 119 |
| Derivatives | 166 | 160 |
| Accumulated deferred income taxes | 366 | 319 |
| Other | 241 | 208 |
| | 3,887 | 3,768 |
| PROPERTY, PLANT AND EQUIPMENT: | | |
| In service | 44,228 | 43,210 |
| Less — Accumulated provision for depreciation | 13,280 | 12,467 |
| | 30,948 | 30,743 |
| Construction work in progress | 2,304 | 2,293 |
| | 33,252 | 33,036 |
| INVESTMENTS: | | |
| Nuclear plant decommissioning trusts | 2,201 | 2,204 |
| Investments in lease obligation bonds | 33 | 54 |
| Other | 870 | 936 |
| | 3,104 | 3,194 |
| ASSETS HELD FOR SALE (Note 20) | 235 | — |
| DEFERRED CHARGES AND OTHER ASSETS: | | |
| Goodwill | 6,418 | 6,447 |
| Regulatory assets | 1,854 | 2,330 |
| Other | 1,674 | 1,719 |
| | 9,946 | 10,496 |
| | $50,424 | $50,494 |
| LIABILITIES AND CAPITALIZATION | | |
| CURRENT LIABILITIES: | | |
| Currently payable long-term debt | $1,415 | $1,999 |
| Short-term borrowings | 3,404 | 1,969 |
| Accounts payable | 1,250 | 1,599 |
| Accrued taxes | 485 | 543 |
| Accrued compensation and benefits | 351 | 331 |
| Derivatives | 111 | 126 |
| Other | 621 | 1,038 |
| | 7,637 | 7,605 |
| CAPITALIZATION: | | |
| Common stockholders’ equity- | | |

| | | |
|---|---|---|
| Common stock, $0.10 par value, authorized 490,000,000 shares - 418,628,559 shares outstanding | 42 | 42 |
| Other paid-in capital | 9,776 | 9,769 |
| Accumulated other comprehensive income | 284 | 385 |
| Retained earnings | 2,590 | 2,888 |
| Total common stockholders' equity | 12,692 | 13,084 |
| Noncontrolling interest | 3 | 9 |
| Total equity | 12,695 | 13,093 |
| Long-term debt and other long-term obligations | 15,831 | 15,179 |
| | 28,526 | 28,272 |
| NONCURRENT LIABILITIES: | | |
| Accumulated deferred income taxes | 6,968 | 6,616 |
| Retirement benefits | 2,689 | 3,080 |
| Asset retirement obligations | 1,678 | 1,599 |
| Deferred gain on sale and leaseback transaction | 858 | 892 |
| Adverse power contract liability | 290 | 506 |
| Other | 1,778 | 1,924 |
| | 14,261 | 14,617 |
| COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16) | | |
| | $50,424 | $50,494 |

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

| (In millions, except share amounts) | Common Stock Number of Shares | Common Stock Par Value | Other Paid-In Capital | Accumulated Other Comprehensive Income | Retained Earnings |
|---|---|---|---|---|---|
| Balance, January 1, 2011 | 304,835,407 | $31 | $5,444 | $425 | $3,084 |
| Earnings available to FirstEnergy Corp. | | | | | 885 |
| Amortized losses on derivative hedges, net of $8 million of income taxes | | | | 15 | |
| Change in unrealized gain on investments, net of $7 million of income taxes | | | | 12 | |
| Pensions and OPEB, net of $64 million of income tax benefits (Note 3) | | | | (26) | |
| Stock-based compensation | | | 5 | | |
| Allegheny merger | 113,381,030 | 11 | 4,316 | | |
| Cash dividends declared on common stock | | | | | (922) |
| Balance, December 31, 2011 | 418,216,437 | 42 | 9,765 | 426 | 3,047 |
| Earnings available to FirstEnergy Corp. | | | | | 770 |
| Amortized losses on derivative hedges, net of $1 million of income tax benefits | | | | 2 | |
| Change in unrealized gain on investments, net of $2 million of income tax benefits | | | | (4) | |
| Pensions and OPEB, net of $76 million of income tax benefits (Note 3) | | | | (39) | |
| Stock-based compensation | | | 4 | | |
| Cash dividends declared on common stock | | | | | (920) |
| Equity method adjustment (Note 9) | | | | | (9) |
| Balance, December 31, 2012 | 418,216,437 | 42 | 9,769 | 385 | 2,888 |
| Earnings available to FirstEnergy Corp. | | | | | 392 |
| Amortized losses on derivative hedges, net of $1 million of income taxes | | | | 2 | |
| Change in unrealized gain on investments, net of $4 million of income tax benefits | | | | (6) | |
| Pensions and OPEB, net of $63 million of income tax benefits (Note 3) | | | | (97) | |
| Stock-based compensation | | | (4) | | |
| Cash dividends declared on common stock | | | | | (690) |
| Stock issuance - employee benefits | 412,122 | | 11 | | |
| Balance, December 31, 2013 | 418,628,559 | $42 | $9,776 | $284 | $2,590 |

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

| | For the Years Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2013 | 2012 | 2011 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net Income | $392 | $771 | $869 |
| Adjustments to reconcile net income to net cash from operating activities- | | | |
| Provision for depreciation | 1,202 | 1,119 | 1,062 |
| Asset removal costs charged to income | 20 | 203 | 55 |
| Amortization of regulatory assets, net | 539 | 307 | 474 |
| Deferral of storm costs | — | (375) | (145) |
| Nuclear fuel amortization | 209 | 210 | 201 |
| Deferred purchased power and other costs | (76) | (238) | (278) |
| Deferred income taxes and investment tax credits, net | 243 | 647 | 798 |
| Impairments of long-lived assets | 795 | — | 413 |
| Investment impairments | 90 | 27 | 19 |
| Deferred rents and lease market valuation liability | (54) | (104) | (49) |
| Pensions and OPEB mark-to-market adjustment | (256) | 609 | 507 |
| Retirement benefits | (168) | (127) | (151) |
| Gain on asset sales | (21) | (17) | (545) |
| Commodity derivative transactions, net (Note 10) | 4 | (95) | (27) |
| Pension trust contributions | — | (600) | (372) |
| Cash collateral, net | (42) | 16 | (79) |
| Gain on sale of investment securities held in trusts, net | (56) | (71) | (59) |
| Loss on debt redemptions | 132 | — | — |
| Make-whole premiums paid on debt redemptions | (187) | — | — |
| Income from discontinued operations (Note 20) | (17) | (16) | (13) |
| Decrease (increase) in operating assets- | | | |
| Receivables | (114) | (13) | 147 |
| Materials and supplies | 96 | (50) | 14 |
| Prepayments and other current assets | (126) | (12) | 101 |
| Increase (decrease) in operating liabilities- | | | |
| Accounts payable | (25) | 100 | 60 |
| Accrued taxes | 85 | (2) | 83 |
| Accrued interest | (10) | (12) | (12) |
| Accrued compensation and benefits | 19 | (55) | 69 |
| Other | (12) | 98 | (79) |
| Net cash provided from operating activities | 2,662 | 2,320 | 3,063 |
| | | | |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| New Financing- | | | |
| Long-term debt | 3,745 | 750 | 604 |
| Short-term borrowings, net | 1,435 | 1,969 | — |
| Redemptions and Repayments- | | | |
| Long-term debt | (3,600) | (940) | (1,909) |
| Short-term borrowings, net | — | — | (700) |
| Tender premiums paid on debt redemptions | (110) | — | — |
| Common stock dividend payments | (920) | (920) | (881) |

| | | | |
|---|---|---|---|
| Other | (73) | (52) | (38) |
| Net cash provided from (used for) financing activities | 477 | 807 | (2,924) |
| | | | |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Property additions | (2,638) | (2,678) | (2,129) |
| Nuclear fuel | (250) | (286) | (149) |
| Proceeds from asset sales | 4 | 17 | 840 |
| Sales of investment securities held in trusts | 2,047 | 2,980 | 4,207 |
| Purchases of investment securities held in trusts | (2,096) | (3,020) | (4,309) |
| Cash investments | (23) | 102 | 60 |
| Cash received in Allegheny merger | — | — | 590 |
| Asset removal costs | (146) | (229) | (114) |
| Other | 9 | (43) | 48 |
| Net cash used for investing activities | (3,093) | (3,157) | (956) |
| | | | |
| Net change in cash and cash equivalents | 46 | (30) | (817) |
| Cash and cash equivalents at beginning of period | 172 | 202 | 1,019 |
| Cash and cash equivalents at end of period | $218 | $172 | $202 |
| | | | |
| SUPPLEMENTAL CASH FLOW INFORMATION: | | | |
| Non-cash transaction: common stock issued in merger with Allegheny | $— | $— | $4,354 |
| Cash paid (received) during the year - | | | |
| Interest (net of amounts capitalized) | $969 | $962 | $935 |
| Income taxes | $36 | $(6) | $(358) |

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

| | For the Years Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2013 | 2012 | 2011 |
| STATEMENTS OF INCOME (LOSS) | | | |
| REVENUES: | | | |
| Electric sales to non-affiliates | $5,378 | $5,253 | $4,478 |
| Electric sales to affiliates | 652 | 515 | 752 |
| Other | 143 | 126 | 223 |
| Total revenues | 6,173 | 5,894 | 5,453 |
| OPERATING EXPENSES: | | | |
| Fuel | 1,262 | 1,287 | 1,344 |
| Purchased power from affiliates | 486 | 451 | 242 |
| Purchased power from non-affiliates | 2,333 | 1,887 | 1,381 |
| Other operating expenses | 1,487 | 1,356 | 1,619 |
| Pensions and OPEB mark-to-market adjustment | (81) | 166 | 171 |
| Provision for depreciation | 306 | 272 | 272 |
| General taxes | 138 | 136 | 124 |
| Impairment of long-lived assets | — | — | 294 |
| Total operating expenses | 5,931 | 5,555 | 5,447 |
| OPERATING INCOME | 242 | 339 | 6 |
| OTHER INCOME (EXPENSE): | | | |
| Loss on debt redemptions | (103) | — | — |
| Investment income | 16 | 66 | 57 |
| Miscellaneous income | 28 | 35 | 30 |
| Interest expense — affiliates | (10) | (10) | (8) |
| Interest expense — other | (160) | (191) | (203) |
| Capitalized interest | 39 | 37 | 35 |
| Total other expense | (190) | (63) | (89) |
| INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES | 52 | 276 | (83) |
| INCOME TAXES (BENEFITS) | 6 | 103 | (16) |
| INCOME (LOSS) FROM CONTINUING OPERATIONS | $46 | $173 | $(67) |
| Discontinued operations (net of income taxes of $8, $8 and $5, respectively) (Note 20) | 14 | 14 | 8 |
| NET INCOME (LOSS) | $60 | $187 | $(59) |
| STATEMENTS OF COMPREHENSIVE INCOME (LOSS) | | | |

| | | | |
|---|---|---|---|
| NET INCOME (LOSS) | $60 | $187 | $(59) |
| | | | |
| OTHER COMPREHENSIVE INCOME (LOSS): | | | |
| Pensions and OPEB prior service costs | (15) | 6 | (12) |
| Amortized losses (gains) on derivative hedges | (6) | (9) | 12 |
| Change in unrealized gain on available-for-sale securities | (8) | (5) | 16 |
| Other comprehensive income (loss) | (29) | (8) | 16 |
| Income taxes (benefits) on other comprehensive income (loss) | (11) | (4) | 2 |
| Other comprehensive income (loss), net of tax | (18) | (4) | 14 |
| | | | |
| COMPREHENSIVE INCOME (LOSS) | $42 | $183 | $(45) |

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

| (In millions, except share amounts) | December 31, 2013 | December 31, 2012 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $2 | $3 |
| Receivables- | | |
| Customers, net of allowance for uncollectible accounts of $11 in 2013 and $16 in 2012 | 539 | 483 |
| Affiliated companies | 1,036 | 379 |
| Other, net of allowance for uncollectible accounts of $3 in 2013 and $2 in 2012 | 81 | 91 |
| Notes receivable from affiliated companies | — | 276 |
| Materials and supplies | 448 | 505 |
| Derivatives | 165 | 158 |
| Prepayments and other | 138 | 87 |
| | 2,409 | 1,982 |
| PROPERTY, PLANT AND EQUIPMENT: | | |
| In service | 12,472 | 11,997 |
| Less — Accumulated provision for depreciation | 4,755 | 4,408 |
| | 7,717 | 7,589 |
| Construction work in progress | 1,308 | 1,141 |
| | 9,025 | 8,730 |
| INVESTMENTS: | | |
| Nuclear plant decommissioning trusts | 1,276 | 1,283 |
| Other | 11 | 12 |
| | 1,287 | 1,295 |
| ASSETS HELD FOR SALE (Note 20) | 122 | — |
| DEFERRED CHARGES AND OTHER ASSETS: | | |
| Customer intangibles | 95 | 110 |
| Goodwill | 23 | 24 |
| Property taxes | 41 | 36 |
| Unamortized sale and leaseback costs | 168 | 119 |
| Derivatives | 53 | 99 |
| Other | 279 | 253 |
| | 659 | 641 |
| | $13,502 | $12,648 |
| LIABILITIES AND CAPITALIZATION | | |
| CURRENT LIABILITIES: | | |
| Currently payable long-term debt | $892 | $1,102 |
| Short-term borrowings- | | |
| Affiliated companies | 431 | — |
| Other | 4 | 4 |
| Accounts payable- | | |
| Affiliated companies | 765 | 726 |
| Other | 290 | 159 |

| | | |
|---|---|---|
| Accrued taxes | 66 | 171 |
| Derivatives | 110 | 124 |
| Other | 197 | 280 |
| | 2,755 | 2,566 |
| CAPITALIZATION: | | |
| Common stockholder's equity- | | |
| Common stock, without par value, authorized 750 shares- 7 shares outstanding | 3,080 | 1,573 |
| Accumulated other comprehensive income | 54 | 72 |
| Retained earnings | 2,178 | 2,118 |
| Total common stockholder's equity | 5,312 | 3,763 |
| Long-term debt and other long-term obligations | 2,130 | 3,118 |
| | 7,442 | 6,881 |
| NONCURRENT LIABILITIES: | | |
| Deferred gain on sale and leaseback transaction | 858 | 892 |
| Accumulated deferred income taxes | 741 | 515 |
| Asset retirement obligations | 1,015 | 965 |
| Retirement benefits | 185 | 241 |
| Derivatives | 14 | 37 |
| Other | 492 | 551 |
| | 3,305 | 3,201 |
| COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16) | | |
| | $13,502 | $12,648 |

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

| (In millions, except share amounts) | Common Stock Number of Shares | Common Stock Carrying Value | Accumulated Other Comprehensive Income | Retained Earnings |
|---|---|---|---|---|
| Balance, January 1, 2011 | 7 | $1,567 | $62 | $1,990 |
| Net loss | | | | (59) |
| Amortized gain on derivative hedges, net of $5 of income taxes | | | 7 | |
| Change in unrealized gain on investments, net of $6 of income taxes | | | 10 | |
| Pensions and OPEB, net of $9 of income tax benefits (Note 3) | | | (3) | |
| Consolidated tax benefit allocation | | 3 | | |
| Balance, December 31, 2011 | 7 | 1,570 | 76 | 1,931 |
| Net income | | | | 187 |
| Amortized loss on derivative hedges, net of $3 of income tax benefits | | | (6) | |
| Change in unrealized gain on investments, net of $2 of income tax benefits | | | (3) | |
| Pensions and OPEB, net of $1 of income taxes (Note 3) | | | 5 | |
| Stock-based compensation | | 2 | | |
| Consolidated tax benefit allocation | | 1 | | |
| Balance, December 31, 2012 | 7 | 1,573 | 72 | 2,118 |
| Net income | | | | 60 |
| Amortized loss on derivative hedges, net of $2 of income tax benefits | | | (4) | |
| Change in unrealized gain on investments, net of $3 of income tax benefits | | | (5) | |
| Pensions and OPEB, net of $6 of income tax benefits (Note 3) | | | (9) | |
| Equity contribution from parent | | 1,500 | | |
| Stock-based compensation | | 1 | | |
| Consolidated tax benefit allocation | | 6 | | |
| Balance, December 31, 2013 | 7 | $3,080 | $54 | $2,178 |

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

| | For the Years Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2013 | 2012 | 2011 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net Income (Loss) | $60 | $187 | $(59) |
| Adjustments to reconcile net income (loss) to net cash from operating activities- | | | |
| Provision for depreciation | 306 | 272 | 272 |
| Nuclear fuel amortization | 209 | 210 | 200 |
| Deferred rents and lease market valuation liability | (49) | (100) | (42) |
| Deferred income taxes and investment tax credits, net | 309 | 214 | 199 |
| Impairments of long-lived assets | — | — | 294 |
| Investment impairments | 79 | 14 | 17 |
| Pensions and OPEB mark-to-market adjustment | (81) | 166 | 171 |
| Retirement benefits | (2) | (7) | (43) |
| Pension trust contribution | — | (209) | — |
| Gain on investment securities held in trusts | (49) | (65) | (50) |
| Gain on asset sales | (20) | (17) | — |
| Commodity derivative transactions, net (Note 10) | 5 | (74) | (68) |
| Cash collateral, net | (34) | (33) | (88) |
| Loss on debt redemptions | 103 | — | — |
| Make-whole premiums paid on debt redemptions | (31) | — | — |
| Income from discontinued operations (Note 20) | (14) | (14) | (8) |
| Decrease (increase) in operating assets- | | | |
| Receivables | (393) | 135 | (126) |
| Materials and supplies | 57 | (13) | 16 |
| Prepayments and other current assets | (39) | (18) | 22 |
| Increase (decrease) in operating liabilities- | | | |
| Accounts payable | (145) | 240 | (38) |
| Accrued taxes | (207) | (64) | 154 |
| Accrued compensation and benefits | 2 | 8 | 2 |
| Other | 12 | (11) | (6) |
| Net cash provided from operating activities | 78 | 821 | 819 |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| New financing- | | | |
| Long-term debt | — | 650 | 247 |
| Short-term borrowings, net | 431 | 3 | — |
| Equity contribution from parent | 1,500 | — | — |
| Redemptions and repayments- | | | |
| Long-term debt | (1,202) | (429) | (856) |
| Short-term borrowings, net | — | — | (11) |
| Tender premiums paid on debt redemptions | (67) | — | — |
| Other | (9) | (12) | (11) |
| Net cash provided from (used for) financing activities | 653 | 212 | (631) |

| | | | |
|---|---|---|---|
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Property additions | (717) | (795) | (600) |
| Nuclear fuel | (250) | (286) | (149) |
| Proceeds from asset sales | 21 | 17 | 599 |
| Sales of investment securities held in trusts | 940 | 1,464 | 1,843 |
| Purchases of investment securities held in trusts | (1,000) | (1,502) | (1,890) |
| Loans to affiliated companies, net | 276 | 107 | 14 |
| Other | (2) | (42) | (7) |
| Net cash used for investing activities | (732) | (1,037) | (190) |
| | | | |
| Net change in cash and cash equivalents | (1) | (4) | (2) |
| Cash and cash equivalents at beginning of period | 3 | 7 | 9 |
| Cash and cash equivalents at end of period | $2 | $3 | $7 |
| | | | |
| SUPPLEMENTAL CASH FLOW INFORMATION: | | | |
| Cash paid (received) during the year - | | | |
| Interest (net of amounts capitalized) | $157 | $174 | $167 |
| Income taxes | $23 | $72 | $(387) |

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

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy’s principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FES and its principal subsidiaries (FG and NG), FESC and during 2013, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP, FET and its principal subsidiaries (ATSI, TrAIL and PATH), and AESC). In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc. As of January 1, 2014, AE merged with and into FirstEnergy Corp., therefore, AE's direct subsidiaries, AE Supply, MP, PE, WP and FET, became direct subsidiaries of FirstEnergy Corp.

FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the 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, 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. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation unless certain regulatory restrictions and rules apply. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 8, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. 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 and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with our sale of hydro assets discussed in additional detail in Note 20, Discontinued Operations and Assets Held for Sale. Additionally, amounts collected in rates above actual charges related to asset removal have been reclassified as a regulatory liability which resulted in an increase to total assets and noncurrent liabilities of approximately $88 million.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, ATSI, PATH and TrAIL 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.

FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

The following table provides information about the composition of net regulatory assets as of December 31, 2013 and December 31, 2012, and the changes during the year ended December 31, 2013:

| Regulatory Assets by Source | December 31, 2013 | December 31, 2012 | Increase (Decrease) |
|---|---|---|---|
| | (In millions) | | |
| Regulatory transition costs | $266 | $293 | $(27) |
| Customer receivables for future income taxes | 518 | 505 | 13 |
| Nuclear decommissioning and spent fuel disposal costs | (198) | (219) | 21 |
| Asset removal costs | (362) | (372) | 10 |
| Deferred transmission costs | 112 | 352 | (240) |
| Deferred generation costs | 346 | 379 | (33) |
| Deferred distribution costs | 194 | 231 | (37) |
| Contract valuations | 260 | 463 | (203) |
| Storm-related costs | 455 | 469 | (14) |
| Other | 263 | 229 | 34 |
| Total | $1,854 | $2,330 | $(476) |

Regulatory assets that do not earn a current return totaled approximately $477 million as of December 31, 2013 primarily related to storm damage costs.

As of December 31, 2013 and December 31, 2012, FirstEnergy had approximately $440 million and $480 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. FES' and AE Supply's principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements of the Ohio and Pennsylvania Companies and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. Retail customers are metered on a cycle basis.

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities, FES and AE Supply accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES and AE Supply. There was no material concentration of receivables as of December 31, 2013 and 2012 with respect to any particular segment of FirstEnergy’s customers. Billed and unbilled customer receivables as of December 31, 2013 and 2012 are shown below.

| Customer Receivables | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| December 31, 2013 | | |
| Billed | $1,010 | $301 |
| Unbilled | 710 | 238 |
| Total | $1,720 | $539 |

| | | |
|---|---|---|
| December 31, 2012 | | |
| Billed | $893 | $243 |
| Unbilled | 721 | 240 |
| Total | $1,614 | $483 |

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

| Reconciliation of Basic and Diluted Earnings per Share of Common Stock | 2013 | 2012 | 2011 |
|---|---|---|---|
| | (In millions, except per share amounts) | | |
| Income from continuing operations | $375 | $755 | $856 |
| Less: Income attributable to noncontrolling interest | — | 1 | (16) |
| Income from continuing operations available to common shareholders | 375 | 754 | 872 |
| Discontinued operations (Note 20) | 17 | 16 | 13 |
| Earnings available to FirstEnergy Corp. | $392 | $770 | $885 |
| | | | |
| Weighted average number of basic shares outstanding | 418 | 418 | 399 |
| Assumed exercise of dilutive stock options and awards[1] | 1 | 1 | 2 |
| Weighted average number of diluted shares outstanding | 419 | 419 | 401 |
| | | | |
| Earnings per share: | | | |
| Basic earnings per share: | | | |
| Continuing operations | $0.90 | $1.81 | $2.19 |
| Discontinued operations (Note 20) | 0.04 | 0.04 | 0.03 |
| Net earnings per basic share | $0.94 | $1.85 | $2.22 |
| | | | |
| Diluted earnings per share: | | | |
| Continuing operations | $0.90 | $1.80 | $2.18 |
| Discontinued operations (Note 20) | 0.04 | 0.04 | 0.03 |
| Net earnings per diluted share | $0.94 | $1.84 | $2.21 |

(1) For the year ended December 31, 2013, 2 million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect were not significant for the years ending December 31, 2012 or 2011.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the specific identification method. Net plant in service balances as of December 31, 2013 and 2012 were as follows:

| | December 31, 2013 | | | December 31, 2012 | | |
|---|---|---|---|---|---|---|
| Property, Plant and Equipment | In Service | Accum. Depr. | Net Plant | In Service | Accum. Depr. | Net Plant |
| | (In millions) | | | | | |
| Regulated Distribution | $23,098 | $(6,514) | $16,584 | $21,473 | $(6,146) | $15,327 |
| Regulated Transmission | 5,564 | (1,511) | 4,053 | 5,078 | (1,451) | 3,627 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Competitive | 15,206 | (5,088) | 10,118 | 16,338 | (4,739) | 11,599 |
| Other/Corporate | 360 | (167) | 193 | 321 | (131) | 190 |
| Total | $44,228 | $(13,280) | $30,948 | $43,210 | $(12,467) | $30,743 |

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 and FES' electric plant in 2013, 2012 and 2011 are shown in the following table:

| | Annual Composite Depreciation Rate | | | | | |
|---|---|---|---|---|---|---|
| | 2013 | | 2012 | | 2011 | |
| FirstEnergy | 2.6 | % | 2.5 | % | 2.4 | % |
| FES | 3.1 | % | 3.1 | % | 3.1 | % |

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,000 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, Plant and Equipment includes $672 million, excluding $28 million of CWIP, representing AGC's share in this facility as of December 31, 2013. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statement of Income.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset. AROs as of December 31, 2013, are described further in Note 14, Asset Retirement Obligations.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value. Impairments of long-lived assets recognized for the year ended December 31, 2013, are described further in Note 11, Impairment of Long-Lived Assets.

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. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, Competitive Energy Services and Other/Corporate. Goodwill is allocated to these reportable segments based on the original purchase price allocation of acquisitions. Total goodwill recognized by segment in FirstEnergy's Consolidated Balance Sheet is as follows:

| Goodwill | Regulated Distribution | Regulated Transmission | Competitive Energy Services | Other/Corporate | Consolidated |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Balance as of December 31, 2012 | $5,025 | $526 | $896 | $ — | $6,447 |
| Classification to Assets Held for Sale[1] | — | — | (29) | — | (29) |
| West Virginia asset transfer | 67 | — | (67) | — | — |
| Balance as of December 31, 2013 | $5,092 | $526 | $800 | $ — | $6,418 |

(1) See Note 20, Discontinued Operations and Assets Held for Sale.

As of December 31, 2013 and 2012, total goodwill recognized by FES was $23 million and $24 million, respectively. Neither FirstEnergy nor FES has accumulated impairment charges as of December 31, 2013.

Annual impairment testing is conducted as of July 31 of each year and for 2013, 2012 and 2011, the analysis indicated no impairment of goodwill. FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission segments as of July 31, 2013. FirstEnergy assessed economic, industry and market considerations in addition to overall financial performance of its Regulated Distribution and Regulated Transmission segments. It was determined that the fair values of these segments were, more likely than not, greater than their carrying values.

Due to excess generation supply in the region, which has caused a period of protracted low power and capacity prices impacting Competitive operations, FirstEnergy performed a quantitative assessment of the Competitive Energy Services segment as of July 31, 2013. The fair value of the Competitive Energy Services segment was calculated using a discounted cash flow analysis which included the effects of the potential sale of certain hydroelectric power stations and the West Virginia asset transfer. Assumptions used in the analysis include discount rates, market performance, projected operating and capital cash flows and the fair value of debt. The estimated fair value of the Competitive Energy Services segment exceeded its carrying amount (including goodwill) as of July 31, 2013. Continued weak economic conditions, lower than forecasted power and capacity prices, and revised environmental requirements could have a negative impact on future goodwill assessments.

In October of 2013, in connection with the closing of the West Virginia asset transfer, as discussed in Note 15, Regulatory Matters, FirstEnergy transferred approximately $67 million of goodwill, net from the Competitive Energy Services segment to the Regulated Distribution segment based on the relative fair value of the generating plants to the fair value of the respective segment.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS 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 an equity security 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 an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. In 2013, 2012 and 2011, FirstEnergy recognized $90 million, $16 million and $19 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $79 million, $14 million and $17 million, respectively. The fair values of FirstEnergy’s investments are disclosed in Note 9, Fair Value Measurements.

INVENTORY

Materials and supplies inventory includes fuel inventory and the distribution, transmission and generation plant materials, net of reserve for excess and obsolete inventory. Materials are generally charged to inventory at weighted average cost when purchased and expensed or capitalized, as appropriate, when used or installed. Fuel inventory is accounted for at weighted average cost when purchased, and recorded to fuel expense when consumed.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

2. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, for the years ended December 31, 2013, 2012 and 2011 for FirstEnergy and FES are shown in the following tables:
FirstEnergy

| | Gains & Losses on Cash Flow Hedges | Unrealized Gains on AFS Securities | Defined Benefit Pension & OPEB Plans | Total |
|---|---|---|---|---|
| | (In millions) | | | |
| AOCI Balance, January 1, 2011 | $(54) | $7 | $472 | $425 |
| Other comprehensive income (loss) before reclassifications | (9) | 49 | 78 | 118 |
| Amounts reclassified from AOCI | 24 | (37) | (104) | (117) |
| Net other comprehensive income (loss) | 15 | 12 | (26) | 1 |
| AOCI Balance, December 31, 2011 | $(39) | $19 | $446 | $426 |
| Other comprehensive income before reclassifications | — | 41 | 79 | 120 |
| Amounts reclassified from AOCI | 1 | (45) | (117) | (161) |
| Net other comprehensive income (loss) | 1 | (4) | (38) | (41) |
| AOCI Balance, December 31, 2012 | $(38) | $15 | $408 | $385 |
| Other comprehensive income before reclassifications | — | 29 | 23 | 52 |
| Amounts reclassified from AOCI | 2 | (35) | (120) | (153) |
| Net other comprehensive income (loss) | 2 | (6) | (97) | (101) |
| AOCI Balance, December 31, 2013 | $(36) | $9 | $311 | $284 |

FES

| | Gains & Losses on Cash Flow Hedges (In millions) | Unrealized Gains on AFS Securities | Defined Benefit Pension & OPEB Plans | Total |
|---|---|---|---|---|
| AOCI Balance, January 1, 2011 | $1 | $6 | $55 | $62 |
| Other comprehensive income (loss) before reclassifications | (9) | 42 | 8 | 41 |
| Amounts reclassified from AOCI | 16 | (32) | (11) | (27) |
| Net other comprehensive income (loss) | 7 | 10 | (3) | 14 |
| AOCI Balance, December 31, 2011 | $8 | $16 | $52 | $76 |
| Other comprehensive income before reclassifications | — | 38 | 16 | 54 |
| Amounts reclassified from AOCI | (5) | (41) | (12) | (58) |
| Net other comprehensive income (loss) | (5) | (3) | 4 | (4) |
| AOCI Balance, December 31, 2012 | $3 | $13 | $56 | $72 |
| Other comprehensive income before reclassifications | — | 26 | 3 | 29 |
| Amounts reclassified from AOCI | (4) | (31) | (12) | (47) |
| Net other comprehensive loss | (4) | (5) | (9) | (18) |
| AOCI Balance, December 31, 2013 | $(1) | $8 | $47 | $54 |

The following amounts were reclassified from AOCI in the years ended December 31, 2013, 2012 and 2011 for FirstEnergy and FES are shown in the following tables:

| FirstEnergy<br>Reclassifications from AOCI [2] | Year Ended December 31<br>2013 | <br>2012 | <br>2011 | Affected Line Item in Consolidated<br>Statements of Income |
|---|---|---|---|---|
| | (In millions) | | | |
| Gains & losses on cash flow hedges | | | | |
| Commodity contracts | $(8) | $(9) | $26 | Other operating expenses |
| Long-term debt | 11 | 10 | 12 | Interest expense |
| | 3 | 1 | 38 | Total before taxes |
| | (1) | — | (14) | Income tax benefits |
| | $2 | $1 | $24 | Net of tax |
| | | | | |
| Unrealized gains on AFS securities | | | | |
| Realized gains on sales of securities | $(56) | $(72) | $(59) | Investment income |
| | 21 | 27 | 22 | Income taxes |
| | $(35) | $(45) | $(37) | Net of tax |
| | | | | |
| Defined benefit pension and OPEB plans | | | | |
| Prior-service costs | $(195) | $(191) | $(169) | [1] |
| | 75 | 74 | 65 | Income taxes |
| | $(120) | $(117) | $(104) | Net of tax |

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.
[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

| FES<br>Reclassifications from AOCI [2] | Year Ended December 31<br>2013 | <br>2012 | <br>2011 | Affected Line Item in Consolidated<br>Statements of Income |
|---|---|---|---|---|
| | (In millions) | | | |
| Gains & losses on cash flow hedges | | | | |
| Commodity contracts | $(8) | $(9) | $26 | Other operating expenses |
| Long-term debt | 2 | — | 1 | Interest expense - other |
| | (6) | (9) | 27 | Total before taxes |
| | 2 | 4 | (11) | Income taxes (benefits) |
| | $(4) | $(5) | $16 | Net of tax |
| | | | | |
| Unrealized gains on AFS securities | | | | |
| Realized gains on sales of securities | $(49) | $(65) | $(51) | Investment income |
| | 18 | 24 | 19 | Income taxes |
| | $(31) | $(41) | $(32) | Net of tax |
| | | | | |
| Defined benefit pension and OPEB plans | | | | |
| Prior-service costs | $(20) | $(20) | $(18) | [1] |
| | 8 | 8 | 7 | Income taxes |
| | $(12) | $(12) | $(11) | Net of tax |

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.

(2) Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

3. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover 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. In addition, 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 certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pensions and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. On July 25, 2013, FirstEnergy announced that non-bargaining employees hired on or after January 1, 2014 will participate in a cash-balance defined benefit pension plan. The plan for existing employees will remain unchanged. Under the cash-balance pension plan, FirstEnergy will make contributions to eligible employee retirement accounts based on employee age and years of service. The balance of these accounts will be provided to employees when they leave the company.

FirstEnergy’s pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2013, FirstEnergy did not make any contributions to its qualified pension plan. Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

| Obligations and Funded Status | Pensions 2013 | 2012 | OPEB 2013 | 2012 |
|---|---|---|---|---|
| | (In millions) | | | |
| Change in benefit obligation: | | | | |
| Benefit obligation as of January 1 | $8,975 | $7,977 | $1,076 | $1,037 |
| Service cost | 197 | 161 | 13 | 12 |
| Interest cost | 372 | 389 | 37 | 47 |
| Plan participants' contributions | — | — | 15 | 17 |
| Plan amendments | 2 | 8 | (37) | (85) |
| Medicare retiree drug subsidy | — | — | 5 | — |
| Actuarial (gain) loss | (846) | 861 | (107) | 152 |
| Benefits paid | (437) | (421) | (123) | (104) |
| Benefit obligation as of December 31 | $8,263 | $8,975 | $879 | $1,076 |
| Change in fair value of plan assets: | | | | |
| Fair value of plan assets as of January 1 | $6,671 | $5,867 | $508 | $528 |
| Actual return on plan assets | (77) | 611 | 56 | 48 |
| Company contributions | 14 | 614 | 39 | 19 |
| Plan participants' contributions | — | — | 15 | 17 |
| Benefits paid | (437) | (421) | (123) | (104) |
| Fair value of plan assets as of December 31 | $6,171 | $6,671 | $495 | $508 |
| Funded Status: | | | | |
| Qualified plan | $(1,782) | $(1,967) | | |
| Non-qualified plans | (310) | (336) | | |
| Funded Status | $(2,092) | $(2,303) | $(384) | $(566) |
| Accumulated benefit obligation | $7,800 | $8,355 | $— | $— |
| Amounts Recognized on the Balance Sheet: | | | | |
| Current liabilities | $(15) | $(14) | $— | $— |
| Noncurrent liabilities | (2,077) | (2,289) | (384) | (566) |
| Net liability as of December 31 | $(2,092) | $(2,303) | $(384) | $(566) |
| Amounts Recognized in AOCI: | | | | |
| Prior service cost (credit) | $48 | $58 | $(558) | $(728) |
| Assumptions Used to Determine Benefit Obligations (as of December 31) | | | | |
| Discount rate | 5.00% | 4.25% | 4.75% | 4.00% |
| Rate of compensation increase | 4.20% | 4.70% | N/A | N/A |
| Assumed Health Care Cost Trend Rates (as of December 31) | | | | |
| Health care cost trend rate assumed (pre/post-Medicare) | N/A | N/A | 7.25-7.75% | 7.5-8.0% |
| | N/A | N/A | 5% | 5% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Rate to which the cost trend rate is assumed to decline (the ultimate trend rate) | | | | | | | | |
| Year that the rate reaches the ultimate trend rate (pre/post-Medicare) | N/A | | N/A | | 2020 | | 2020 | |
| | | | | | | | | |
| Allocation of Plan Assets (as of December 31) | | | | | | | | |
| Equity securities | 18 | % | 15 | % | 47 | % | 39 | % |
| Bonds | 40 | % | 47 | % | 40 | % | 40 | % |
| Absolute return strategies | 23 | % | 22 | % | 3 | % | 4 | % |
| Real estate | 6 | % | 5 | % | 1 | % | 1 | % |
| Private equities | — | % | 1 | % | — | % | — | % |
| Cash and short-term securities | 13 | % | 10 | % | 9 | % | 16 | % |
| Total | 100 | % | 100 | % | 100 | % | 100 | % |

The estimated 2014 amortization of pensions and OPEB prior service costs (credits) from AOCI into net periodic pensions and OPEB costs (credits) is approximately $8 million and $(176) million, respectively.

| Components of Net Periodic Benefit Costs | Pensions 2013 | 2012 | 2011 | OPEB 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|
| | (In millions) | | | | | |
| Service cost | $197 | $161 | $130 | $13 | $12 | $13 |
| Interest cost | 372 | 389 | 374 | 37 | 47 | 48 |
| Expected return on plan assets | (501) | (486) | (446) | (34) | (37) | (40) |
| Amortization of prior service cost (credit) | 12 | 12 | 14 | (207) | (203) | (203) |
| Other adjustments (settlements, curtailments, etc.) | — | — | 6 | — | — | — |
| Pensions & OPEB mark-to-market adjustment | (267) | 735 | 729 | (129) | 140 | 36 |
| Net periodic cost | $(187) | $811 | $807 | $(320) | $(41) | $(146) |

| Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31[1] | Pensions 2013 | 2012 | 2011 | OPEB 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|
| Weighted-average discount rate | 4.25 % | 5.00 % | 5.50 % | 4.00 % | 4.75 % | 5.00 % |
| Expected long-term return on plan assets | 7.75 % | 7.75 % | 8.25 % | 7.75 % | 7.75 % | 8.50 % |
| Rate of compensation increase | 4.70 % | 5.20 % | 5.20 % | N/A | N/A | N/A |

[1] Excludes Pensions & OPEB mark-to-market adjustment.

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 pensions and OPEB obligations. The assumed rates of return on 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.

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 9, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2013 and 2012.

| | December 31, 2013 Level 1 | Level 2 | Level 3 | Total | Asset Allocation |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| Cash and short-term securities | $— | $782 | $— | $782 | 13 % |
| Equity investments | | | | | |
| Domestic | 701 | 3 | — | 704 | 11 % |
| International | 304 | 118 | — | 422 | 7 % |
| Fixed income | | | | | |
| Government bonds | — | 314 | — | 314 | 5 % |
| Corporate bonds | — | 2,128 | — | 2,128 | 34 % |
| Mortgaged-backed securities (non-government) | — | 87 | — | 87 | 1 % |
| Alternatives | | | | | |
| Hedge funds | — | 1,395 | — | 1,395 | 23 % |
| Derivatives | — | 14 | — | 14 | — % |
| Private equity funds | — | — | 27 | 27 | — % |
| Real estate funds | — | — | 385 | 385 | 6 % |
| Total [1] | $1,005 | $4,841 | $412 | $6,258 | 100 % |

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| | December 31, 2012 | | | | Asset | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Allocation | |
| | (In millions) | | | | | |
| Cash and short-term securities | $— | $652 | $— | $652 | 10 | % |
| Equity investments | | | | | | |
| Domestic | 547 | 8 | — | 555 | 8 | % |
| International | 275 | 153 | — | 428 | 7 | % |
| Fixed income | | | | | | |
| Government bonds | 4 | 564 | — | 568 | 8 | % |
| Corporate bonds | — | 1,899 | — | 1,899 | 28 | % |
| High yield debt | — | 369 | — | 369 | 6 | % |
| Mortgaged-backed securities (non-government) | — | 330 | — | 330 | 5 | % |
| Alternatives | | | | | | |
| Hedge funds | — | 1,498 | — | 1,498 | 22 | % |
| Derivatives | — | 18 | — | 18 | — | % |
| Private equity funds | — | — | 33 | 33 | 1 | % |
| Real estate funds | — | — | 357 | 357 | 5 | % |
| Total [(1)] | $826 | $5,491 | $390 | $6,707 | 100 | % |

(1) Excludes ($87) million and ($36) million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2013 and 2012:

| | Private Equity Funds | | Real Estate Funds | | Derivatives | |
|---|---|---|---|---|---|---|
| | (In millions) | | | | | |
| Balance as of January 1, 2012 | $135 | | $327 | | $70 | |
| Actual return on plan assets: | | | | | | |
| Unrealized gains | (14 | ) | 29 | | — | |
| Realized gains | (10 | ) | 4 | | — | |
| Purchases, sales and settlements | — | | — | | (70 | ) |
| Transfers in (out) | (78 | ) | (3 | ) | — | |
| Balance as of December 31, 2012 | $33 | | $357 | | $— | |
| Actual return on plan assets: | | | | | | |
| Unrealized gains | 1 | | 17 | | — | |
| Realized gains | 5 | | 13 | | — | |
| Purchases, sales and settlements | — | | — | | — | |
| Transfers out | (12 | ) | (2 | ) | — | |
| Balance as of December 31, 2013 | $27 | | $385 | | $— | |

As of December 31, 2013 and 2012, the OPEB trust investments measured at fair value were as follows:

| | December 31, 2013 | | | | Asset | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Allocation | |
| | (In millions) | | | | | |
| Cash and short-term securities | $— | $47 | $— | $47 | 9 | % |
| Equity investment | | | | | | |
| Domestic | 227 | — | — | 227 | 45 | % |
| International | 4 | 2 | — | 6 | 1 | % |
| Mutual funds | 5 | — | — | 5 | 1 | % |
| Fixed income | | | | | | |
| U.S. treasuries | — | 44 | — | 44 | 9 | % |
| Government bonds | — | 91 | — | 91 | 18 | % |
| Corporate bonds | — | 59 | — | 59 | 12 | % |
| High yield debt | — | — | — | — | — | % |
| Mortgage-backed securities (non-government) | — | 3 | — | 3 | 1 | % |
| Alternatives | | | | | | |
| Hedge funds | — | 17 | — | 17 | 3 | % |
| Private equity funds | — | — | — | — | — | % |
| Real estate funds | — | — | 5 | 5 | 1 | % |
| Total (1) | $236 | $263 | $5 | $504 | 100 | % |

| | December 31, 2012 | | | | Asset | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Allocation | |
| | (In millions) | | | | | |
| Cash and short-term securities | $— | $83 | $— | $83 | 16 | % |
| Equity investment | | | | | | |
| Domestic | 183 | — | — | 183 | 36 | % |
| International | 4 | 2 | — | 6 | 1 | % |
| Mutual funds | 8 | 3 | — | 11 | 2 | % |
| Fixed income | | | | | | |
| U.S. treasuries | — | 48 | — | 48 | 9 | % |
| Government bonds | — | 88 | — | 88 | 17 | % |
| Corporate bonds | — | 59 | — | 59 | 11 | % |
| High yield debt | — | 5 | — | 5 | 1 | % |
| Mortgage-backed securities (non-government) | — | 9 | — | 9 | 2 | % |
| Alternatives | | | | | | |
| Hedge funds | — | 21 | — | 21 | 4 | % |
| Private equity funds | — | — | — | — | — | % |
| Real estate funds | — | — | 5 | 5 | 1 | % |
| Total (1) | $195 | $318 | $5 | $518 | 100 | % |

(1) Excludes ($9) million and ($10) million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2013 and 2012:

| | Private Equity Funds | Real Estate Funds |
|---|---|---|
| | (in millions) | |
| Balance as of January 1, 2012 | $3 | $7 |
| Actual return on plan assets: | | |
| Unrealized losses | (1) | — |
| Realized gains (losses) | — | — |
| Purchases, sales and settlements | — | — |
| Transfers out | (2) | (2) |
| Balance as of December 31, 2012 | $— | $5 |
| Balance as of December 31, 2013 | $— | $5 |

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

FirstEnergy's target asset allocations for its pensions and OPEB trust portfolios for 2013 and 2012 are shown in the following table:

| | Target Asset Allocations | |
|---|---|---|
| | 2013 | 2012 |
| Equities | 26% | 20% |
| Fixed income | 40% | 51% |
| Absolute return strategies | 22% | 21% |
| Real estate | 5% | 5% |
| Private equity | 1% | —% |
| Cash | 6% | 3% |
| | 100% | 100% |

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 | $1 | $(1) |
| Effect on accumulated benefit obligation | $26 | $(23) |

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

| | Pensions | OPEB Benefit Payments | OPEB Subsidy Receipts |
|---|---|---|---|
| | (in millions) | | |
| 2014 | $449 | $129 | $(4) |
| 2015 | 466 | 67 | (4) |
| 2016 | 484 | 67 | (4) |
| 2017 | 500 | 67 | (4) |
| 2018 | 524 | 65 | (4) |
| Years 2019-2023 | 2,867 | 382 | (17) |

FES' share of the net pensions and OPEB liability as of December 31, 2013 and 2012, was as follows:

| | Pensions | | OPEB | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| | (In millions) | | | |
| Net Liability | $(149) | $(180) | $(8) | $(36) |

FES' share of the net periodic pensions and OPEB costs for the three years ended December 31, 2013 was as follows:

| | Pensions | | | OPEB | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | 2013 | 2012 | 2011 |
| | (In millions) | | | | | |
| Net Periodic Costs | $(30) | $78 | $80 | $(40) | $(11) | $(21) |

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4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation plans - ICP, 401(k) Savings Plan, EDCP and DCPD, as described further below.

ICP

The ICP includes four forms of stock-based compensation — restricted stock, restricted stock units, stock options and performance shares.

Under the ICP, total issuances cannot exceed 29 million shares of common stock or their equivalent. Stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from eight months to ten years. Performance share awards are currently designated to be paid in cash unless the recipient elects to defer the award, in which case, the award may be paid in stock depending upon the duration of the deferral. Shares available under the ICP are also used for bonuses earned under FirstEnergy's Short-Term Incentive Program that are, at the election of the participant, deferred through the EDCP and paid in shares under the ICP. As of December 31, 2013, approximately 3.0 million shares were available for future issuance plus any shares that become available again under the ICP due to cancellations, forfeitures, cash settlements or other similar circumstances with respect to outstanding awards.

FirstEnergy records the compensation costs for stock-based compensation awards over the vesting period based on the fair value on the grant date, less estimated forfeitures. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2013, 2012 and 2011 were $13 million, $22 million and $14 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as an other financing activity on the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Restricted common stock (restricted stock) and restricted stock units (stock units) activity for the year ended December 31, 2013, was as follows:

| | |
|---|---|
| Outstanding as of January 1, 2013 | 2,180,422 |
| Granted | 952,137 |
| Vested | (815,851) |
| Forfeited | (100,099) |
| Outstanding as of December 31, 2013 | 2,216,609 |

The 952,137 shares of restricted stock and stock units granted during the year ended December 31, 2013, includes 212,211 stock units related to previous grants due to over-achievement of performance metrics, and had a grant-date fair value of $39.97 and a weighted-average vesting period of 3.02 years.

Eligible employees receive awards of FE restricted stock or stock units subject to restrictions that lapse over a defined period of time or upon achieving performance results. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted stock grants under the ICP were as follows:

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| Restricted stock granted | 27,561 | 263,771 | 297,859 |
| Weighted average market price | $42.53 | $44.82 | $38.44 |
| Weighted average vesting period (years) | 3.68 | 3.09 | 2.27 |

| | | | |
|---|---|---|---|
| Dividends restricted | Yes | Yes | Yes |

Vesting activity for restricted stock during 2013 was as follows (forfeitures were not material):

| Restricted Stock | Number of Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested as of January 1, 2013 | 551,678 | $46.73 |
| Nonvested as of December 31, 2013 | 417,464 | $45.46 |
| Granted in 2013 | 27,561 | $42.53 |
| Vested in 2013[1] | 167,751 | $37.10 |

[1] Includes 23,446 shares for dividends earned during vesting period

FirstEnergy grants two types of stock unit awards: discretionary-based and performance-based. The discretionary-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in each agreement. Performance-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets.

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| Restricted stock units granted | 924,576 | 652,120 | 617,195 |
| Weighted average vesting period (years) | 3.00 | 3.00 | 3.00 |

Vesting activity for stock units during 2013 was as follows:

| Restricted Stock Units | Number of Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested as of January 1, 2013 | 1,628,744 | $41.10 |
| Nonvested as of December 31, 2013 | 1,799,145 | $40.86 |
| Granted in 2013 | 924,576 | $39.90 |
| Forfeited in 2013 | 82,629 | $41.38 |
| Vested in 2013 [1] | 792,113 | $40.74 |

[1] Includes dividend equivalents of 120,567 earned during vesting period

As of December 31, 2013, there was $35 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock and restricted stock units; that cost is expected to be recognized over a period of approximately 2 years.

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 activity during 2013 was as follows:

| Stock Option Activity | Number of Shares | | Weighted Average Exercise Price |
|---|---|---|---|
| Balance, January 1, 2013 (2,348,469 options exercisable) | 2,910,269 | | $40.33 |
| Options exercised | (546,408 | ) | 30.37 |
| Options forfeited | (4,735 | ) | 71.21 |
| Balance, December 31, 2013 (1,997,969 options exercisable) | 2,359,126 | | $42.59 |

Options outstanding and range of exercise prices as of December 31, 2013, were as follows:

| | Options Outstanding | | |
|---|---|---|---|
| Range of Exercise Prices | Shares | Weighted Average Exercise Price | Remaining Contractual Life (in years) |
| $20.02-$35.44 | 66,125 | $22.83 | 0.47 |
| $35.45-$38.75 | 1,143,389 | $36.78 | 6.28 |
| $38.76-$53.04 | 835,039 | $38.81 | 0.19 |
| $53.05-$81.19 | 314,573 | $77.85 | 3.56 |
| Total | 2,359,126 | $42.59 | 3.60 |

Cash received from the exercise of stock options in 2013, 2012 and 2011 was $19 million, $50 million and $32 million, respectively. The total intrinsic value of options exercised during 2013 was $6 million.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FE's common stock over a three-year vesting period. During that time, dividend equivalents accrue and at vesting are converted into additional performance shares. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. During 2013, 2012 and 2011, no cash was paid to settle performance shares due to the criteria not being met for the previous three-year vesting period.

401(k) Savings Plan

In 2013, 2012 and 2011, shares of FE common stock were purchased on the market and contributed to participants' accounts.

EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into unfunded FE stock accounts to receive vested stock units or into an unfunded retirement cash account. Dividends are calculated quarterly on stock units outstanding and are credited in the form of additional stock units. Upon withdrawal, stock units are converted to FE shares. Payout of the stock accounts 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. Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement.

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their equity retainers to deferred stock and their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $7 million and $6 million as of December 31, 2013 and December 31, 2012, respectively, is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

Of the approximately 1.7 million shares authorized under the EDCP and DCPD, approximately 845,000 shares were available for future issuance as of December 31, 2013. The shareholder approved pools for the EDCP and DCPD terminate in May 2014.

Stock-based Compensation Expense

Pre-tax stock-based compensation costs, tax benefit associated with stock-based compensation expense, and the amount of stock-based compensation expense capitalized related to FirstEnergy and FES plans are included in the following tables:

| FirstEnergy | Years ended December 31, | | |
|---|---|---|---|
| Stock-based Compensation Plan | 2013 | 2012 | 2011 |
| | (In millions) | | |
| Restricted Stock and Restricted Stock Units | $42 | $42 | $29 |
| Stock Options | — | 1 | 1 |
| Performance Shares | (10) | 5 | 3 |
| 401(k) Savings Plan | 25 | 37 | 31 |
| EDCP | (2) | — | 6 |
| DCPD | 5 | 4 | 4 |
| Total | $60 | $89 | $74 |
| Stock-based compensation costs capitalized | $20 | $29 | $21 |

| FES | Years ended December 31, | | |
|---|---|---|---|
| Stock-based Compensation Plan | 2013 | 2012 | 2011 |
| | (In millions) | | |
| Restricted Stock and Restricted Stock Units | $6 | $6 | $4 |
| Performance Shares | (1) | 1 | 1 |
| 401(k) Savings Plan | 4 | 6 | 5 |
| EDCP | — | — | 1 |
| Total | $9 | $13 | $11 |
| Stock-based compensation costs capitalized | $1 | $1 | $— |

Tax benefits associated with stock based compensation plan expense was $23 million, $11 million and $10 million (FES - $1 million, $2 million and $2 million) for the years ended 2013, 2012 and 2011, respectively.

5. TAXES

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

| PROVISION FOR INCOME TAXES | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| 2013 | | |
| Currently payable (receivable)- | | |
| Federal | $(118) | $(300) |
| State | 70 | (3) |
| | (48) | (303) |
| Deferred, net- | | |
| Federal | 305 | 317 |
| State | (54) | (4) |
| | 251 | 313 |
| Investment tax credit amortization | (8) | (4) |
| Total provision for income taxes | $195 | $6 |
| | | |
| 2012 | | |
| Currently payable (receivable)- | | |
| Federal | $(130) | $(128) |
| State | 28 | 17 |
| | (102) | (111) |
| Deferred, net- | | |
| Federal | 580 | 209 |
| State | 78 | 9 |
| | 658 | 218 |
| Investment tax credit amortization | (11) | (4) |
| Total provision for income taxes | $545 | $103 |
| | | |
| 2011 | | |
| Currently payable (receivable)- | | |
| Federal | $(251) | $(224) |
| State | 19 | 9 |
| | (232) | (215) |
| Deferred, net- | | |
| Federal | 785 | 205 |
| State | 24 | (2) |
| | 809 | 203 |
| Investment tax credit amortization | (11) | (4) |
| Total provision for income taxes | $566 | $(16) |

As discussed in Note 11, on July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating two coal-fired generating plants. As a result of the decision, FirstEnergy determined that it is more likely than not that certain state and local NOL carryforwards will not be realized through future operations or through the reversal of existing temporary differences. As a result, FirstEnergy recorded a valuation reserve of approximately $20 million against carryforwards in 2013.

On July 9, 2013, Pennsylvania House Bill 465 (HB 465) was enacted, adopting new market-based sourcing rules for certain items of income as well as increasing the Pennsylvania NOL deduction credit for tax years beginning after December 31, 2013 and 2014 to the greater of 25% or $4 million of taxable income and 30% or $5 million of taxable income, respectively. Based on income projections, Pennsylvania NOL valuation reserves were reduced by approximately $8 million in 2013.

During 2013, FirstEnergy made changes to state apportionment factors in certain jurisdictions based on sales sourcing rules for electricity, which reduced deferred tax liabilities by approximately $9 million. Furthermore, based on an assessment of business operations, FirstEnergy determined that income from certain subsidiaries should not be apportioned to certain tax jurisdictions due to the absence of business nexus. This assessment resulted in a reduction to deferred tax liabilities of approximately $22 million.

In 2012, a $50 million valuation allowance was established for two unregulated subsidiaries of FirstEnergy based on current judgment as to the realization of certain state deferred tax assets, as impacted by changes in the business and the applicability of certain state law limitations on the long-term utilization of NOL carryforwards. The results of operations in 2012 for those companies decreased accumulated deferred income tax liabilities by approximately $50 million.

In December 2012, two subsidiaries of FES, FG and NG, completed a conversion from corporations to limited liability companies (LLCs). For income tax purposes, these LLCs are treated as divisions (i.e., disregarded entities) of their parent company, FES. The LLC conversions, in combination with anticipated future taxable income, will contribute to the realization of certain state deferred tax assets. In 2011, an unregulated subsidiary of FirstEnergy converted to an LLC which, based on anticipated future taxable income, resulted in the partial reversal of a valuation allowance, reducing income tax expense in 2011 by $27 million.

During 2012, certain FirstEnergy operating companies adopted a new federal tax accounting method (effective for the 2011 consolidated federal tax return) for the deductibility of expenses for repairs to transmission and distribution assets, pursuant to IRS safe harbor guidance. In accordance with the IRS guidance, a cumulative adjustment was made on the 2011 consolidated federal tax return, increasing tax deductions and decreasing taxable income by approximately $417 million. The increased federal tax deductions created a corresponding state tax benefit that reduced FirstEnergy's effective tax rate by approximately $12 million in 2012. The IRS has agreed that the new method of accounting is compliant with the IRS guidance.

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

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31, 2013:

| | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| 2013 | | |
| Book income before provision for income taxes | $570 | $52 |
| Federal income tax expense at statutory rate | $199 | $18 |
| Increases (reductions) in taxes resulting from- | | |
| Amortization of investment tax credits | (8) | (4) |
| State income taxes, net of federal tax benefit | 10 | (5) |
| FirstEnergy effectively settled tax items | (2) | — |
| ESOP Dividend | (9) | (2) |
| Nondeductible compensation | 3 | — |
| Other permanent items | 1 | — |
| AFUDC equity and other flow-through | (7) | — |
| Other, net | 8 | (1) |
| Total provision for income taxes | $195 | $6 |
| | | |
| 2012 | | |
| Book income before provision for income taxes | $1,299 | $276 |
| Federal income tax expense at statutory rate | $455 | $97 |
| Increases (reductions) in taxes resulting from- | | |
| Amortization of investment tax credits | (11) | (4) |
| State income taxes, net of federal tax benefit | 69 | 17 |
| Medicare Part D | 32 | 1 |
| Effectively settled tax items | (20) | (11) |
| State valuation allowance | 60 | — |
| State apportionment remeasurement | (50) | — |
| Other, net | 10 | 3 |
| Total provision for income taxes | $545 | $103 |
| | | |
| 2011 | | |
| Book income before provision for income taxes | $1,438 | $(83) |
| Federal income tax expense (benefit) at statutory rate | $503 | $(29) |
| Increases (reductions) in taxes resulting from- | | |
| Amortization of investment tax credits | (11) | (4) |
| State income taxes, net of federal tax benefit | 28 | 5 |
| State unitary tax adjustments | 33 | — |
| Manufacturing deduction | 16 | 13 |
| Medicare Part D | 36 | 4 |
| Effectively settled tax items | (11) | (2) |
| State valuation allowance | (19) | 2 |
| Other, net | (9) | (5) |
| Total provision for income taxes (benefits) | $566 | $(16) |

Accumulated deferred income taxes as of December 31, 2013 and 2012 are as follows:

| | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| December 31, 2013 | | |
| Property basis differences | $8,078 | $1,428 |
| Regulatory transition charge | (26) | — |
| Customer receivables for future income taxes | (2) | — |
| Deferred MISO/PJM transmission costs | 27 | — |
| Other regulatory assets — RCP | 69 | — |
| Deferred sale and leaseback gain | (411) | (370) |
| Non-utility generation costs | (1) | — |
| Unamortized investment tax credits | (62) | (16) |
| Unrealized losses on derivative hedges | (20) | (1) |
| Pensions and OPEB | (938) | (77) |
| Lease market valuation liability | (59) | 55 |
| Oyster Creek securitization (Note 12) | 57 | — |
| Nuclear decommissioning activities | 44 | 31 |
| Mark-to-market adjustments | 31 | 30 |
| Deferred gain for asset sales — affiliated companies | 781 | — |
| Loss carryforwards and AMT credits | (1,599) | (369) |
| Loss carryforward valuation reserve | 142 | 18 |
| Storm damage | 179 | — |
| Market transition charge | 81 | — |
| All other | 231 | (13) |
| Net deferred income tax liability | $6,602 | $716 |
| | | |
| December 31, 2012 | | |
| Property basis differences | $7,868 | $1,060 |
| Regulatory transition charge | 79 | — |
| Customer receivables for future income taxes | 130 | — |
| Deferred MISO/PJM transmission costs | 125 | — |
| Other regulatory assets — RCP | 161 | — |
| Deferred sale and leaseback gain | (431) | (384) |
| Non-utility generation costs | 5 | — |
| Unamortized investment tax credits | (67) | (17) |
| Unrealized losses on derivative hedges | (21) | 2 |
| Pensions and OPEB | (1,102) | (105) |
| Lease market valuation liability | (81) | 33 |
| Oyster Creek securitization (Note 12) | 75 | — |
| Nuclear decommissioning activities | 127 | 111 |
| Mark-to-market adjustments | 30 | 30 |
| Loss carryforwards and ATM credits | (1,199) | (221) |
| Loss carryforward valuation reserve | 102 | 16 |
| Storm damage | 192 | — |
| Market transition charge | 65 | — |
| All other | 239 | (22) |
| Net deferred income tax liability | $6,297 | $503 |

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2013 and 2012, FirstEnergy's total unrecognized income tax benefits were approximately $48 million and $43 million, respectively. All $48 million of unrecognized income tax benefits as of December 31, 2013, would impact the effective tax rate if ultimately recognized in future years. As of December 31, 2013, it is

reasonably possible that approximately $35 million of unrecognized tax benefits may be resolved during 2014 as a result of the statute of limitations expiring, all of which would affect FirstEnergy's effective tax rate.
During 2013, the AE companies reduced reserves for unrecognized tax benefits related to various tax positions, with a total reduction to the effective tax rate of approximately $5 million.

During 2013, FirstEnergy settled a claim with the IRS for approximately $1.0 billion of additional accelerated (bonus) depreciation deductions for certain generation property for the 2010 taxable year, which resulted in a carryback refund of approximately $110 million, an increase in the NOL carryfoward of approximately $65 million, with a corresponding increase to accumulated deferred income taxes for this temporary tax item and an overall decrease to FirstEnergy's effective tax rate of approximately $2 million for adjustments to interest resulting from the settlement.
During 2012, FirstEnergy reached a settlement with state authorities related to state apportionment factors in Pennsylvania on an intercompany asset sale, which reduced FirstEnergy's effective tax rate by $3 million. During 2012, based on further IRS guidance related to the tax accounting for costs to repair and maintain fixed assets, the AE companies reduced their amount of unrecognized tax benefits by $21 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, with no resulting impact to the effective tax rate.
During the fourth quarter of 2012, FirstEnergy reached a settlement with the IRS on deductions for prior year costs to repair generation assets, permitting the reduction of unrecognized tax benefits by approximately $34 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, and an overall decrease to FirstEnergy's effective tax rate of approximately $10 million for adjustments to potential interest expense resulting from the settlement. Also during the fourth quarter of 2012, the AE companies reduced reserves for unrecognized tax benefits related to various tax positions, including the IRS's agreement on AE's deduction of merger-related expenses, with a total reduction to the effective tax rate of approximately $7 million.
The following table summarizes the changes in unrecognized tax positions for the years ended 2013, 2012 and 2011:

| | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| Balance, January 1, 2011 | $45 | $41 |
| Increase due to merger with AE | 97 | — |
| Prior years increases | 10 | 8 |
| Prior years decreases | (35) | (4) |
| Balance, December 31, 2011 | $117 | $45 |
| Current year increases | 2 | — |
| Current year decreases | (7) | — |
| Prior years increases | 6 | 6 |
| Prior years decreases | (37) | (13) |
| Decrease for settlements | (38) | (35) |
| Balance, December 31, 2012 | $43 | $3 |
| Prior years increases | 10 | — |
| Prior years decreases | (5) | — |
| Balance, December 31, 2013 | $48 | $3 |

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. FirstEnergy's reversal of accrued interest associated with unrecognized tax benefits was immaterial to FirstEnergy's effective tax rate in 2013 and reduced the 2012 effective tax rate by approximately $4 million. The interest associated with the 2011 settlement of a claim favorably affected FirstEnergy's effective tax rate by $7 million in 2011.
The following table summarizes the net interest expense (income) for the three years ended December 31, 2013 and the cumulative net interest payable as of December 31, 2013 and 2012:

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| | Net Interest Expense (Income) For the Years Ended December 31, | | | Net Interest Payable As of December 31, | |
|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | 2013 | 2012 |
| | (In millions) | | | (In millions) | |
| FirstEnergy | $1 | $(4) | $(5) | $9 | $8 |
| FES | — | (4) | 1 | 1 | 1 |

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2011-2013) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2009-2012. The IRS completed its audit of the 2011 tax year in December 2013 and is in the process of preparing the final audit report. Tax years 2012-2013 are under review by the IRS. In August 2013 the IRS completed its audit of AE for tax years 2009 and 2010 and the final federal tax return for the period January-February 2011. For the remainder of the 2011 taxable year and future years, the AE companies are part of the FirstEnergy federal consolidated group. State tax returns for tax years 2010 through 2012 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE.

FirstEnergy has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2013, the deferred income tax assets, before any valuation allowances, consisted of $1.1 billion of federal NOL carryforwards that expire from 2025 to 2033, federal AMT credits of $25 million that have an indefinite carryforward period, and $418 million of state and local NOL carryforwards that begin to expire in 2014.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $9.8 billion for FirstEnergy, of which approximately $6.3 billion is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

| Expiration Period | FirstEnergy | | FES | |
|---|---|---|---|---|
| | (In millions) | | | |
| | State | Local | State | Local |
| 2014-2018 | $14 | $2,289 | $8 | $1,243 |
| 2019-2023 | 2,513 | — | 23 | — |
| 2024-2028 | 2,051 | — | 60 | — |
| 2029-2033 | 2,891 | — | 752 | — |
| | $7,469 | $2,289 | $843 | $1,243 |

General Taxes

| | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| 2013 | | |
| KWH excise | $219 | $— |
| State gross receipts | 240 | 77 |
| Real and personal property | 368 | 40 |
| Social security and unemployment | 110 | 19 |
| Other | 41 | 2 |
| Total general taxes | $978 | $138 |
| 2012 | | |
| KWH excise | $230 | $— |
| State gross receipts | 251 | 77 |
| Real and personal property | 328 | 35 |
| Social security and unemployment | 126 | 20 |
| Other | 49 | 4 |
| Total general taxes | $984 | $136 |
| 2011 | | |
| KWH excise | $244 | $— |
| State gross receipts | 264 | 62 |
| Real and personal property | 298 | 42 |
| Social security and unemployment | 109 | 14 |
| Other | 62 | 6 |
| Total general taxes | $977 | $124 |

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.

In 2007, FG completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years. FES has unconditionally and irrevocably guaranteed all of FG’s obligations under each of the leases.

During 2008, NG 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, NG 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.

During 2012, NG repurchased 70.1 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million and FG acquired 441.9 MW of certain equity and other lessor interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $262 million. In March of 2013, FG acquired the remaining lessor interests in the Bruce Mansfield sale and leaseback transaction for approximately $221 million. During 2013, NG purchased 12.2 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million. Additionally, in February 2014, NG purchased 47.7 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million.

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. During 2013, the investments held at Shippingport were liquidated. The PNBV arrangements effectively reduce lease costs related to those transactions (see Note 8, Variable Interest Entities).

As of December 31, 2013, FirstEnergy's leasehold interest was 8.11% of Perry Unit 1 and 93.83% of Bruce Mansfield Unit 1. After NG's purchase in February 2014, as discussed above, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2.

Operating lease expense for 2013, 2012 and 2011, is summarized as follows:

| (In millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| FirstEnergy | $224 | $291 | $319 |

| | | | |
|---|---|---|---|
| FES | 97 | 140 | 154 |

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The future minimum capital lease payments as of December 31, 2013 are as follows:

| Capital leases | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| 2014 | $40 | $6 |
| 2015 | 38 | 6 |
| 2016 | 34 | 5 |
| 2017 | 30 | 5 |
| 2018 | 23 | 2 |
| Years thereafter | 57 | — |
| Total minimum lease payments | 222 | 24 |
| Interest portion | (34) | (2) |
| Present value of net minimum lease payments | 188 | 22 |
| Less current portion | 34 | 5 |
| Noncurrent portion | $154 | $17 |

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2013, are as follows:

| Operating Leases | FirstEnergy Lease Payments | Capital Trust | Net |
|---|---|---|---|
| | (In millions) | | |
| 2014 | $250 | $48 | $202 |
| 2015 | 245 | 40 | 205 |
| 2016 | 213 | 13 | 200 |
| 2017 | 128 | 3 | 125 |
| 2018 | 126 | — | 126 |
| Years thereafter | 1,564 | — | 1,564 |
| Total minimum lease payments | $2,526 | $104 | $2,422 |

FES' future minimum operating lease payments as of December 31, 2013, are as follows:

| Operating Leases | Lease Payments |
|---|---|
| | (In millions) |
| 2014 | $143 |
| 2015 | 142 |
| 2016 | 130 |
| 2017 | 82 |
| 2018 | 101 |
| Years thereafter | 1,480 |
| Total minimum lease payments | $2,078 |

7. INTANGIBLE ASSETS

As of December 31, 2013, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, include the following:

| | Intangible Assets | | | Amortization Expense | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Actual | Estimated | | | | | |
| (In millions) | Gross | Accumulated Amortization | Net | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
| NUG contracts(1)(2) | $124 | $15 | $109 | $5 | $5 | $5 | $5 | $5 | $5 | $84 |
| OVEC(1) | 54 | 5 | 49 | 2 | 2 | 2 | 2 | 2 | 2 | 39 |
| Coal contracts(1)(3) | 556 | 222 | 334 | 62 | 55 | 51 | 51 | 45 | 30 | 49 |
| FES customer contracts | 147 | 52 | 95 | 17 | 17 | 17 | 17 | 17 | 14 | 13 |
| Energy contracts(1) | 136 | 135 | 1 | 14 | 1 | — | — | — | — | — |
| | $1,017 | $429 | $588 | $100 | $80 | $75 | $75 | $69 | $51 | $185 |

(1) Fair value measurements of intangible assets recorded in connection with the Allegheny merger (see Note 21, Merger).
(2) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.
(3) A gross amount of $102 million ($53 million, net) of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

8. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity's economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy's consolidated financial statements are: FEV's joint venture in the Signal Peak mining and coal transportation operations, a portion of which was sold on October 18, 2011, and resulted in deconsolidation; the PNBV and Shippingport capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly-owned limited liability companies of the Ohio Companies (as described below); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities (see Note 12, Capitalization for additional details).

The caption noncontrolling interest within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own. The change in noncontrolling interest within the Consolidated Balance Sheets during the year ended December 31, 2013, was primarily due to $7 million of distributions to owners. As of December 31, 2013, the caption noncontrolling interest on the consolidated Balance Sheets was primarily related to PNBV.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into the following categories based on similar risk characteristics and significance.

Ohio Securitization

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. Each SPE is a bankruptcy-remote, special purpose limited liability company that is restricted to activities necessary to issue phase-in recovery bonds and perform other functions in connection with the bond issuance. Creditors of FirstEnergy and the Ohio Companies have no recourse to any assets or revenues of the SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility. In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million of redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

Mining Operations

In 2008, FEV entered into a joint venture in the Signal Peak mining and coal transportation operations near Roundup, Montana. FEV made equity investments totaling $134 million in exchange for a 50% economic interest in the joint venture. On October 18, 2011, Pinesdale LLC, a subsidiary of Gunvor Group, Ltd., purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. As part of the transaction, FirstEnergy received $258 million in proceeds and retained a 33-1/3% equity ownership in Global Holding, the holding company for the joint venture. The sale resulted in a pre-tax gain of approximately $569 million ($370 million after-tax), which included $379 million from the remeasurement of FEV's retained investment. The gain attributed to the retained investment remeasurement is being amortized as coal is extracted from the mine on a units of production method.

Prior to the sale, FirstEnergy consolidated this joint venture since FEV was determined to be the primary beneficiary of the VIE. As a result of the sale, FEV was no longer determined to be the primary beneficiary and its retained 33-1/3%% interest is subject to the equity method of accounting.

Trusts

FirstEnergy's consolidated financial statements include PNBV and Shippingport. FirstEnergy used debt and available funds to purchase the notes issued by PNBV and Shippingport for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE. During 2013, the investments held at Shippingport were liquidated.

PATH-WV

PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of AE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH project that was to be constructed by PATH-WV.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 15, Regulatory Matters, for additional information on the abandonment of PATH.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant’s variable costs of production. FirstEnergy maintains 21 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities.

FirstEnergy has determined that for all but two of these NUG entities, it does not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold variable interests in the remaining two entities; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $185 million and $253 million during the years ended December 31, 2013 and 2012, respectively.

In 1998 the PPUC issued an order approving a transition plan for WP that disallowed certain costs, including an estimated amount for an adverse power purchase commitment related to the NUG entity wherein WP may hold a variable interest, for which WP has taken the scope exception. On November 20, 2012, WP entered into an agreement to terminate the adverse power purchase commitment and accrued a pre-tax loss of $17 million. WP terminated the adverse commitment on January 1, 2013. WP's liability for this adverse purchase power commitment was $60 million, which included the $17 million accrual and was paid in January 2013.

Sale and Leaseback

FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements. See Note 6, Leases for additional details.

FES, and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions as of December 31, 2013:

| | Maximum Exposure | Discounted Lease Payments, net[(1)] | Net Exposure |
|---|---|---|---|
| | (In millions) | | |
| FES | $1,274 | $1,063 | $211 |
| Other FE subsidiaries | 752 | 289 | 463 |

[(1)] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.1 billion.

## 9. FAIR VALUE MEASUREMENTS

### RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs, NUGs and LCAPPs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 10, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchase power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

LCAPP contracts are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L, pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. LCAPP contracts are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable input into the model is forecasted regional capacity prices. Pricing for the LCAPP contracts is a combination of PJM RPM capacity auction prices and internal models using historical trends and market data for the remaining years under contract. Capacity prices beyond the 2016/2017 delivery year are developed through a simulation of future PJM RPM auctions. The capacity price forecast assumes a continuation of the current PJM RPM market design and is reflective of the regional peak demand growth and generation fleet additions and retirements that underlie FirstEnergy's long-term energy price forecast. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. During the fourth quarter of 2013, all LCAPP contracts were terminated. See Note 10, Derivative Instruments for additional information.

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. There were no changes in valuation methodologies used as of December 31, 2013, from those used as of December 31, 2012. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2013 and 2012. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:
FirstEnergy

| Recurring Fair Value Measurements | December 31, 2013 | | | | December 31, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| Assets | (In millions) | | | | | | | |
| Corporate debt securities | $— | $1,365 | $— | $1,365 | $— | $1,259 | $— | $1,259 |
| Derivative assets - commodity contracts | 7 | 208 | — | 215 | — | 252 | — | 252 |
| Derivative assets - FTRs | — | — | 4 | 4 | — | — | 8 | 8 |
| Derivative assets - NUG contracts(1) | — | — | 20 | 20 | — | — | 36 | 36 |
| Equity securities(2) | 317 | — | — | 317 | 310 | — | — | 310 |
| Foreign government debt securities | — | 109 | — | 109 | — | 126 | — | 126 |
| U.S. government debt securities | — | 165 | — | 165 | — | 179 | — | 179 |
| U.S. state debt securities | — | 228 | — | 228 | — | 299 | — | 299 |
| Other(3) | 187 | 255 | — | 442 | 126 | 227 | — | 353 |
| Total assets | $511 | $2,330 | $24 | $2,865 | $436 | $2,342 | $44 | $2,822 |

Liabilities

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Derivative liabilities - commodity contracts | $(13) | $(100) | $— | $(113) | $(3) | $(151) | $— | $(154) |
| Derivative liabilities - FTRs | — | — | (12) | (12) | — | — | (9) | (9) |
| Derivative liabilities - NUG contracts[1] | — | — | (222) | (222) | — | — | (290) | (290) |
| Derivative liabilities - LCAPP contracts[1] | — | — | — | — | — | — | (144) | (144) |
| Total liabilities | $(13) | $(100) | $(234) | $(347) | $(3) | $(151) | $(443) | $(597) |
| | | | | | | | | |
| Net assets (liabilities)[4] | $498 | $2,230 | $(210) | $2,518 | $433 | $2,191 | $(399) | $2,225 |

(1) NUG and LCAPP contracts are subject to regulatory accounting treatment and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $10 million and $110 million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts, LCAPP contracts, and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2013 and December 31, 2012:

| | NUG Contracts[1] | | | LCAPP Contracts[1] | | | FTRs | | |
|---|---|---|---|---|---|---|---|---|---|
| | Derivative Assets (In millions) | Derivative Liabilities | Net | Derivative Assets | Derivative Liabilities | Net | Derivative Assets | Derivative Liabilities | Net |
| January 1, 2012 Balance | $57 | $(349) | $(292) | $— | $— | $— | $1 | $(23) | $(22) |
| Unrealized gain (loss) | (20) | (180) | (200) | — | 1 | 1 | 6 | (6) | — |
| Purchases | — | — | — | — | (145) | (145) | 13 | (10) | 3 |
| Settlements | (1) | 239 | 238 | — | — | — | (12) | 30 | 18 |
| December 31, 2012 Balance | $36 | $(290) | $(254) | $— | $(144) | $(144) | $8 | $(9) | $(1) |
| Unrealized gain (loss) | (8) | (17) | (25) | — | (22) | (22) | 3 | 1 | 4 |
| Purchases | — | — | — | — | — | — | 6 | (15) | (9) |
| Terminations[2] | — | — | — | — | 166 | 166 | — | — | — |
| Settlements | (8) | 85 | 77 | — | — | — | (13) | 11 | (2) |
| December 31, 2013 Balance | $20 | $(222) | $(202) | $— | $— | $— | $4 | $(12) | $(8) |

(1) Changes in the fair value of NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.
(2) See Note 10, Derivative Instruments.

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2013:

| | Fair Value, Net (In millions) | Valuation Technique | Significant Input | Range | Weighted Average | Units |
|---|---|---|---|---|---|---|
| FTRs | $(8) | Model | RTO auction clearing prices | ($2.80) to $5.20 | $0.60 | Dollars/MWH |
| NUG Contracts | $(202) | Model | Generation<br>Regional electricity prices | 600 to 5,641,000<br>$51.70 to $57.30 | 1,529,000<br>$53.80 | MWH<br>Dollars/MWH |

FES

| Recurring Fair Value Measurements | December 31, 2013 | | | | December 31, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| Assets | (In millions) | | | | | | | |
| Corporate debt securities | $— | $792 | $— | $792 | $— | $703 | $— | $703 |
| Derivative assets - commodity contracts | 7 | 208 | — | 215 | — | 252 | — | 252 |
| Derivative assets - FTRs | — | — | 3 | 3 | — | — | 6 | 6 |
| Equity securities[(1)] | 207 | — | — | 207 | 294 | — | — | 294 |
| Foreign government debt securities | — | 65 | — | 65 | — | 61 | — | 61 |
| U.S. government debt securities | — | 27 | — | 27 | — | 27 | — | 27 |
| Other[(2)] | — | 176 | — | 176 | — | 104 | — | 104 |
| Total assets | $214 | $1,268 | $3 | $1,485 | $294 | $1,147 | $6 | $1,447 |
| | | | | | | | | |
| Liabilities | | | | | | | | |
| Derivative liabilities - commodity contracts | $(13) | $(100) | $— | $(113) | $(3) | $(151) | $— | $(154) |
| Derivative liabilities - FTRs | — | — | (11) | (11) | — | — | (6) | (6) |
| Total liabilities | $(13) | $(100) | $(11) | $(124) | $(3) | $(151) | $(6) | $(160) |
| | | | | | | | | |
| Net assets (liabilities)[(3)] | $201 | $1,168 | $(8) | $1,361 | $291 | $996 | $— | $1,287 |

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(2) Primarily consists of short-term cash investments.
(3) Excludes $9 million and $94 million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2013 and December 31, 2012:

| | Derivative Asset FTRs | Derivative Liability FTRs | Net FTRs |
|---|---|---|---|
| | (In millions) | | |
| January 1, 2012 Balance | $1 | $(7) | $(6) |
| Unrealized gain (loss) | 4 | (4) | — |
| Purchases | 9 | (7) | 2 |
| Settlements | (8) | 12 | 4 |
| December 31, 2012 Balance | $6 | $(6) | $— |
| Unrealized loss | — | (2) | (2) |
| Purchases | 5 | (12) | (7) |
| Settlements | (8) | 9 | 1 |
| December 31, 2013 Balance | $3 | $(11) | $(8) |

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2013:

| | Fair Value, Net (In millions) | Valuation Technique | Significant Input | Range | Weighted Average | Units |
|---|---|---|---|---|---|---|
| FTRs | $(8) | Model | RTO auction clearing prices | ($2.80) to $5.20 | $0.50 | Dollars/MWH |

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, AFS securities and notes receivable.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS 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 an equity security 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 an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI.

The investment policy for the NDT funds restricts or limits the trusts' 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, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

FirstEnergy holds debt and equity securities within its NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of December 31, 2013 and December 31, 2012:

| | December 31, 2013[1] | | | December 31, 2012[2] | | |
|---|---|---|---|---|---|---|
| | Cost Basis | Unrealized Gains | Fair Value | Cost Basis | Unrealized Gains | Fair Value |
| | (In millions) | | | | | |
| Debt securities | | | | | | |
| FirstEnergy | $1,881 | $33 | $1,914 | $1,827 | $34 | $1,861 |
| FES | 918 | 17 | 935 | 778 | 14 | 792 |
| | | | | | | |
| Equity securities | | | | | | |
| FirstEnergy | $308 | $9 | $317 | $293 | $16 | $309 |
| FES | 207 | — | 207 | 281 | 13 | 294 |

[1] Excludes short-term cash investments: FE Consolidated - $204 million; FES - $135 million.
[2] Excludes short-term cash investments: FE Consolidated - $326 million; FES - $196 million.

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Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three years ended December 31, 2013, 2012 and 2011 were as follows:

| December 31, 2013 | Sale Proceeds | Realized Gains | Realized Losses | OTTI | Interest and Dividend Income |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| FirstEnergy | $2,047 | $92 | $(46) | $(90) | $101 |
| FES | 940 | 70 | (21) | (79) | 60 |

| December 31, 2012 | Sale Proceeds | Realized Gains | Realized Losses | OTTI | Interest and Dividend Income |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| FirstEnergy | $2,980 | $179 | $(83) | $(16) | $70 |
| FES | 1,464 | 124 | (59) | (14) | 39 |

| December 31, 2011 | Sale Proceeds | Realized Gains | Realized Losses | OTTI | Interest and Dividend Income |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| FirstEnergy | $4,207 | $229 | $(71) | $(19) | $82 |
| FES | 1,843 | 80 | (29) | (17) | 47 |

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2013 and December 31, 2012:

| | December 31, 2013 | | | December 31, 2012 | | |
|---|---|---|---|---|---|---|
| | Cost Basis | Unrealized Gains | Fair Value | Cost Basis | Unrealized Gains | Fair Value |
| | (In millions) | | | | | |
| Debt Securities | | | | | | |
| FirstEnergy | $33 | $2 | $35 | $54 | $30 | $84 |

Investments in emission allowances, employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $636 million as of December 31, 2013, and $644 million as of December 31, 2012, are excluded from the amounts reported above.

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 as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

| | December 31, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |

| | | | | |
|---|---|---|---|---|
| | (In millions) | | | |
| FirstEnergy | $17,049 | $17,957 | $16,957 | $19,460 |
| FES | 3,001 | 3,073 | 4,194 | 4,524 |

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2013 and December 31, 2012.

## 10. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy’s Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 2020.

### Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates. The effective portion of gains and losses on a derivative contract is reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled $2 million and $10 million as of December 31, 2013 and December 31, 2012, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $10 million is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were 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. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $59 million and $70 million as of December 31, 2013 and December 31, 2012, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months.

As of December 31, 2013 and December 31, 2012, no commodity or interest rate derivatives were designated as cash flow hedges.

Refer to Note 2, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the years ended December 31, 2013 and 2012.

### Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $44 million and $79 million as of December 31, 2013 and December 31, 2012, respectively. Based on current estimates, approximately $12 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $19 million and $22 million during the years ended December 31, 2013 and 2012, respectively. In connection with the redemptions of senior notes by FES, PN, and ME and taxable bonds by CEI and OE, unamortized gains associated with fixed for floating interest rate swap agreements of $17 million were included in the Loss on debt redemptions in the Consolidated Statements of Income for the year ended December 31, 2013. Refer to Note 12, Capitalization, for additional information regarding FirstEnergy's debt redemptions during the year ended December 31, 2013. In 2012, FirstEnergy terminated all forward starting swap agreements resulting in cash proceeds and a net gain, recorded as a reduction to interest expense, of approximately $6 million.

As of December 31, 2013 and December 31, 2012, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy’s combustion turbine units. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2013, FES' net asset position under commodity derivative contracts was $102 million. Under these commodity derivative contracts, FES posted $29 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $1 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of December 31, 2013, an adverse change of 10% in commodity prices would decrease net income by approximately $27 million during the next twelve months.

NUGs

As of December 31, 2013, FirstEnergy's net liability position under NUG contracts was $202 million representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintained two LCAPP contracts, which are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. JCP&L expected to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts are considered derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts were subject to regulatory accounting, changes in their fair value did not impact earnings. On October 11, 2013, the U.S. District Court for the District of New Jersey declared that the LCAPP is preempted by the FPA and unconstitutional. On October 22, 2013, the Superior Court of New Jersey Appellate Division dismissed two consolidated appeals which had been taken from the final order of the NJBPU which accepted and adopted the recommendation of the NJBPU's Agent regarding implementation of the LCAPP law. Dismissal of the consolidated appeals, along with pending matters currently on remand to the NJBPU, was without prejudice subject to the parties exercising their appellate rights in the federal courts. The parties filed an appeal with the U.S. Court of Appeals for the Third Circuit with briefing by the parties to be completed by March 5, 2014. Consistent with the provisions of the LCAPP contracts, the U.S District Court's ruling is a termination event. During the fourth quarter of 2013, JCP&L issued termination notices to the counterparties and reversed the derivative liability and corresponding regulatory asset on its Consolidated Balance Sheet.

FTRs

As of December 31, 2013, FirstEnergy's and FES' net liability position under FTRs was $8 million and FES posted $5 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy’s load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to the RTO, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy’s utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

| Derivative Assets | | | Derivative Liabilities | | |
|---|---|---|---|---|---|
| | Fair Value December 31, 2013 (In millions) | December 31, 2012 | | Fair Value December 31, 2013 (In millions) | December 31, 2012 |
| Current Assets - Derivatives | | | Current Liabilities - Derivatives | | |
| Commodity Contracts | $162 | $153 | Commodity Contracts | $(102) | $(119) |
| FTRs | 4 | 7 | FTRs | (9) | (7) |
| | 166 | 160 | | (111) | (126) |
| | | | Noncurrent Liabilities - Adverse Power Contract Liability | | |
| | | | NUGs | (222) | (290) |
| Deferred Charges and Other Assets - Other | | | LCAAP | — | (144) |
| Commodity Contracts | 53 | 99 | Noncurrent Liabilities - Other | | |
| FTRs | — | 1 | Commodity Contracts | (11) | (36) |
| NUGs | 20 | 36 | FTRs | (3) | (2) |
| | 73 | 136 | | (236) | (472) |
| Derivative Assets | $239 | $296 | Derivative Liabilities | $(347) | $(598) |

FirstEnergy enters into contracts with counterparties that allow for net settlement of derivative assets and derivative liabilities. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

| | | Amounts Not Offset in Consolidated Balance Sheet | | |
|---|---|---|---|---|
| December 31, 2013 | Fair Value | Derivative Instruments | Cash Collateral (Received)/Pledged | Net Fair Value |
| | (In millions) | | | |
| Derivative Assets | | | | |
| Commodity contracts | $215 | $(106) | $(9) | $100 |
| FTRs | 4 | (4) | — | — |
| NUG contracts | 20 | — | — | 20 |
| | $239 | $(110) | $(9) | $120 |
| Derivative Liabilities | | | | |

| | | | | |
|---|---|---|---|---|
| Commodity contracts | $(113) | $106 | $7 | $— |
| FTRs | (12) | 4 | 5 | (3) |
| NUG contracts | (222) | — | — | (222) |
| | $(347) | $110 | $12 | $(225) |

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| December 31, 2012 | Fair Value | Amounts Not Offset in Consolidated Balance Sheet Derivative Instruments | Cash Collateral (Received)/Pledged | Net Fair Value |
|---|---|---|---|---|
| | (In millions) | | | |
| Derivative Assets | | | | |
| Commodity contracts | $252 | $(142) | $(5) | $105 |
| FTRs | 8 | (8) | — | — |
| NUG contracts | 36 | — | — | 36 |
| | $296 | $(150) | $(5) | $141 |
| Derivative Liabilities | | | | |
| Commodity contracts | $(155) | $142 | $12 | $(1) |
| FTRs | (9) | 8 | 1 | — |
| NUG contracts | (290) | — | — | (290) |
| LCAPP contracts | (144) | — | — | (144) |
| | $(598) | $150 | $13 | $(435) |

The following table summarizes the volumes associated with FirstEnergy’s outstanding derivative transactions as of December 31, 2013:

| | Purchases | Sales | Net | Units |
|---|---|---|---|---|
| | (In millions) | | | |
| Power Contracts | 34 | 37 | (3) | MWH |
| FTRs | 43 | — | 43 | MWH |
| NUGs | 11 | — | 11 | MWH |
| Natural Gas | 77 | 3 | 74 | mmBTU |

The effect of derivative instruments not in a hedging relationship on the Consolidated Statements of Income during 2013 and 2012 are summarized in the following tables:

| | Year Ended December 31 | | | |
|---|---|---|---|---|
| | Commodity Contracts | FTRs | Interest Rate Swaps | Total |
| | (In millions) | | | |
| 2013 | | | | |
| Unrealized Gain (Loss) Recognized in: | | | | |
| Other Operating Expense | $11 | $(8) | $— | $3 |
| Realized Gain (Loss) Reclassified to: | | | | |
| Revenues | $46 | $21 | $— | $67 |
| Purchased Power Expense | (38) | — | — | (38) |
| Other Operating Expense | — | (36) | — | (36) |
| Fuel Expense | (2) | — | — | (2) |
| 2012 | | | | |
| Unrealized Gain Recognized in: | | | | |
| Other Operating Expense | $89 | $13 | $— | $102 |
| Realized Gain (Loss) Reclassified to: | | | | |
| Revenues | $302 | $22 | $— | $324 |
| Purchased Power Expense | (277) | — | — | (277) |
| Other Operating Expense | — | (61) | — | (61) |
| Fuel Expense | 5 | — | — | 5 |
| Interest Expense | — | — | 6 | 6 |

The unrealized and realized gains (losses) on FirstEnergy’s derivative instruments subject to regulatory accounting during 2013 and 2012 are summarized in the following table:

| | Year Ended December 31 | | | |
|---|---|---|---|---|
| Derivatives Not in a Hedging Relationship with Regulatory Offset | NUGs | LCAPP | Regulated FTRs | Total |
| | (In millions) | | | |
| 2013 | | | | |
| Unrealized Gain (Loss) on Derivative Instrument | $(23) | $(22) | $1 | $(44) |
| Realized Gain (Loss) on Derivative Instrument | 75 | 166 | (1) | 240 |
| 2012 | | | | |
| Unrealized Gain (Loss) on Derivative Instrument | $(201) | $(144) | $1 | $(344) |
| Realized Gain on Derivative Instrument | 240 | — | 7 | 247 |

The following table provides a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during 2013 and 2012:

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| Derivatives Not in a Hedging Relationship with Regulatory Offset | Year Ended December 31 NUGs | LCAPP | Regulated FTRs | Total |
|---|---|---|---|---|
| | (In millions) | | | |
| Outstanding net liability as of January 1, 2013 | $(254) | $(144) | $— | $(398) |
| Additions/Change in value of existing contracts | (23) | (22) | 1 | (44) |
| Settled contracts | 75 | 166 | (1) | 240 |
| Outstanding net liability as of December 31, 2013 | $(202) | $— | $— | $(202) |
| | | | | |
| Outstanding net liability as of January 1, 2012 | $(293) | $— | $(8) | $(301) |
| Additions/Change in value of existing contracts | (201) | (144) | 1 | (344) |
| Settled contracts | 240 | — | 7 | 247 |
| Outstanding net liability as of December 31, 2012 | $(254) | $(144) | $— | $(398) |

## 11. IMPAIRMENT OF LONG-LIVED ASSETS

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value.

West Virginia Asset Transfer - 2013

On October 9, 2013, MP sold its approximate 8% share of Pleasants at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was repaid in the fourth quarter of 2013. In connection with the closing, in the fourth quarter of 2013, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Additionally, MP recognized a regulatory liability of approximately $23 million in the fourth quarter of 2013 representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station.

Generating Plant Retirements - 2013

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the following generating units by October 9, 2013:

| Generating Units | MW Capacity | Location |
|---|---|---|
| Hatfield's Ferry, Units 1-3 | 1,710 | Masontown, Pennsylvania |
| Mitchell, Units 2-3 | 370 | Courtney, Pennsylvania |

As a result of this decision, in the second quarter of 2013, FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge is included within the results of the Competitive Energy Services segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

Approximately 240 plant employees and generation related positions were affected by these plant deactivations. FirstEnergy recorded approximately $6 million (pre-tax) severance related expenses that were recognized in Other operating expenses in the Consolidated Statements of Income during the year ended 2013.

AE Supply has obligations, such as fuel supply, that could be affected by the plant deactivations and management is currently unable to reasonably estimate potential costs, or a range thereof, that could be incurred.

Generating Plant Retirements - 2011

On January 26, 2012 and February 8, 2012, FG, MP and AE Supply announced the deactivation by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. As a result of this decision, FirstEnergy recorded a pre-tax impairment of $334 million to continuing operations during the year ended 2011. This impairment consisted of a $311 million write down of the carrying value of the plant assets, approximately $5 million in excessive $SO_2$ emission allowances and an $18 million charge for excessive or obsolete inventory at these facilities. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. In February 2014, PJM notified FirstEnergy that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. On July 10, 2012, and as amended on October 31, 2012, FirstEnergy filed with FERC, for informational purposes, the compensation arrangements for these units which will remain in effect for as long as these generating units continue to operate. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. During the year ended December 31, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) as a result of the deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

In addition to the emission allowance impairments in connection with the plant closures, FirstEnergy recorded during 2011, pre-tax impairment charges of approximately $6 million ($1 million for FES and $5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately $16 million ($13 million for FES and $3 million for AE Supply) for excess $SO_2$ emission allowances in inventory that it expected will not be consumed in the future.

Fremont Energy Center

On March 11, 2011, FirstEnergy and American Municipal Power, Inc., entered into an agreement for the sale of Fremont Energy Center, which included two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. The execution of this agreement triggered a need to evaluate the recoverability of the carrying value of the assets associated with the Fremont Energy Center. The estimated fair value of the Fremont Energy Center was based on the purchase price outlined in the sale agreement with American Municipal Power, Inc. The result of this evaluation indicated that the carrying cost of the Fremont Energy Center was not fully recoverable. As a result of the recoverability evaluation, FirstEnergy recorded an impairment charge of $11 million to operating income in the first quarter of 2011. On July 28, 2011, FirstEnergy completed the sale of Fremont Energy Center to American Municipal Power, Inc.

Peaking Facilities

During 2011, FirstEnergy assessed the carrying values of certain peaking facilities that were to be sold or disposed of before the end of their useful lives. The estimated fair values were based on estimated sales prices quoted in an active market and indicated that the carrying costs of the peaking facilities were not fully recoverable. FirstEnergy recorded impairment charges of $23 million during 2011 and on October 18, 2011, FirstEnergy closed on the sale of the Richland and Stryker peaking facilities.

12. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2013, FirstEnergy's unrestricted retained earnings were $2.6 billion. Dividends declared in 2013 were $1.65 per share, which included dividends of $0.55 per share paid in the second, third and fourth quarters of 2013. Dividends declared in 2012 were $2.20 per share, which included dividends of $0.55 per share paid in the second, third and fourth quarter of 2012 and dividends of $0.55 per share paid in the first quarter of 2013. 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. On January 21, 2014 the Board of

Directors declared a quarterly dividend of $0.36 per share to be paid in the first quarter of 2014.
In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to FE from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 50% and 45%, respectively. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy’s subsidiaries’ abilities to pay cash dividends to FirstEnergy as of December 31, 2013.
SIP/DRIP Program

On September 25, 2013, FE filed a registration statement with the SEC to register 4 million shares of common stock to be issued to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan. In addition, during December 2013, FE began fulfilling certain share-based benefit plan obligations through the issuance of authorized but unissued common stock.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2013, as follows:

| | Preferred Stock Shares Authorized | Par Value | Preference Stock 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 | | |
| ME | 10,000,000 | no par | | |
| PN | 11,435,000 | no par | | |
| MP | 940,000 | $100 | | |
| PE | 10,000,000 | $0.01 | | |
| WP | 32,000,000 | no par | | |

As of December 31, 2013, and 2012, there were no preferred or preference shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy and FES as of December 31, 2013 and 2012:

| | As of December 31, 2013 | | As of December 31 | |
|---|---|---|---|---|
| (Dollar amounts in millions) | Maturity Date | Interest Rate | 2013 | 2012 |
| FirstEnergy: | | | | |
| FMBs | 2014 - 2043 | 3.340% - 9.740% | $3,166 | $2,587 |
| Secured notes - fixed rate | 2017 - 2037 | 6.150% - 7.880% | 1,804 | 2,113 |
| Secured notes - variable rate | | | — | 50 |
| Total secured notes | | | 1,804 | 2,163 |
| Unsecured notes - fixed rate | 2014 - 2039 | 3.500% - 7.350% | 11,076 | 11,145 |
| Unsecured notes - variable rate | 2014 - 2015 | 0.020% - 1.665% | 959 | 959 |
| Total unsecured notes | | | 12,035 | 12,104 |
| Capital lease obligations | | | 188 | 176 |
| Unamortized debt premiums | | | 9 | 45 |
| Unamortized fair value adjustments | | | 44 | 103 |
| Currently payable long-term debt | | | (1,415) | (1,999) |
| Total long-term debt and other long-term obligations | | | $15,831 | $15,179 |
| | | | | |
| FES: | | | | |
| Secured notes - fixed rate | 2015 - 2017 | 5.150% - 12.000% | $188 | $689 |
| Secured notes - variable rate | | | — | 50 |
| Total secured notes | | | 188 | 739 |
| Unsecured notes - fixed rate | 2014 - 2039 | 2.150% - 6.800% | 2,077 | 2,769 |
| Unsecured notes - variable rate | 2014 - 2015 | 0.130% - 0.160% | 736 | 686 |
| Total unsecured notes | | | 2,813 | 3,455 |
| Capital lease obligations | | | 22 | 27 |
| Unamortized debt discounts | | | (1) | (1) |
| Currently payable long-term debt | | | (892) | (1,102) |
| Total long-term debt and other long-term obligations | | | $2,130 | $3,118 |

On March 5, 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their concurrent tender offers.

On March 28, 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. The $369 million of FES repurchases consisted of original maturities of $252 million due 2021 and $117 million due 2039. The $294 million of AE Supply repurchases consisted of original maturities of $194 million due 2019 and $100 million due 2039. FES and AE Supply paid $67 million and $43 million, respectively, in tender premiums to repurchase the tendered senior notes. FirstEnergy recorded a loss on debt redemption of $119 million (FES - $71 million), including such premiums and other related expenses. The tender premiums paid are included in cash flows from financing activities in the Consolidated Statement of Cash Flows.

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME 4.95% senior unsecured notes that matured in March 2013 and short-term borrowings.

On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of make-whole premiums paid. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

As discussed in Note 8, Variable Interest Entities, in June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million of redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

During August, the Ohio Companies redeemed an additional $660 million of long-term debt with interest rates ranging from 5.65% to 7.25% and paid approximately $120 million of make-whole premiums which were deferred as a regulatory asset and will be amortized over the original life of the redeemed debt. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows. Additionally, during August, JCP&L issued $500 million of 4.7% unsecured notes due April 2024 and used the proceeds to pay down a portion of its short-term debt obligations.

On November 15, 2013, AE Supply optionally redeemed $235 million of its 7.00% PCRBs due July 15, 2039 at 100% of the principal amount in connection with the deactivation of operations at Hatfield's Ferry.

On November 27, 2013, MP issued $400 million of 4.10% FMBs due April 15, 2024 and $600 million of 5.40% FMBs due December 15, 2043. Proceeds from this offering were used by MP to: (i) repay at maturity $300 million of its FMBs, 7.95% Series due December 15, 2013; (ii) redeem $120 million of its FMBs, 6.70% Series due June 15, 2014; (iii) repay a $572.7 million short-term promissory note originally issued on October 9, 2013 to its affiliate, AE Supply in connection with MP’s acquisition of the remaining ownership of the Harrison Power Station; and (iv) for working capital needs and other general corporate purposes.

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million. On December 26, 2013, PN redeemed $150 million of its 5.13% Senior Notes due April 1,2014 and ME redeemed $100 million of its 4.88% Senior Notes due April 1, 2014.
See Note 6, Leases for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. The right to collect environmental control charges is not included as an asset on FirstEnergy's consolidated balance sheets. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2013 and 2012, $472 million and $493 million of environmental control bonds were outstanding, respectively.

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 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 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. 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. As of December 31, 2013 and 2012, $207 million and $243 million of the transition bonds were outstanding, respectively.

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 thousand that are payable from TBC collections.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors.

Other Long-term Debt

The Ohio Companies, Penn, FG and NG each 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.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2013, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments of $7 million in 2013, all of which relate to Penn. Penn expects to meet its 2013 annual sinking fund requirement with a replacement credit under its mortgage indenture.

As of December 31, 2013, FirstEnergy’s currently payable long-term debt included approximately $809 million (FES — $736 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2013. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2014.

| Year | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| 2014 | $1,376 | $887 |
| 2015 | 1,264 | 391 |
| 2016 | 1,041 | 417 |
| 2017 | 1,641 | 163 |
| 2018 | 1,453 | 266 |

The following table classifies the outstanding fixed rate put PCRBs and variable rate PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs.

| Year | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| 2014 | $835 | $762 |
| 2015 | 313 | 313 |
| 2016 | 391 | 391 |
| 2017 | 130 | 130 |
| 2018 | 125 | 125 |

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FG, NG and the applicable Utilities are entitled to a credit against their obligation to repay those bonds. FG, NG and the applicable Utilities pay annual fees based on 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.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy and FES as of December 31, 2013, are as follows:

| | Aggregate LOC Amount | Annual Fees |
|---|---|---|
| | (In millions) | |
| FirstEnergy | $818 | 1.65% to 3.30% |
| FES | 744 | 1.65% to 3.30% |

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2013, FirstEnergy and FES remain in compliance with all debt covenant provisions. Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by any of AE Supply, FES, FG or NG would generally not cross-default to applicable financing arrangements of FirstEnergy. Also, defaults by FirstEnergy would generally not cross-default applicable financing arrangements of any of FirstEnergy’s subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FirstEnergy, FG, NG or the Utilities.

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had $3,404 million and $1,969 million of short-term borrowings as of December 31, 2013 and December 31, 2012, respectively. FirstEnergy’s available liquidity as of January 31, 2014, was as follows:

| Borrower(s) | Type | Maturity | Commitment | Available Liquidity |
|---|---|---|---|---|
| | | | (In millions) | |
| FirstEnergy(1) | Revolving | May 2018 | $2,500 | $224 |
| FES / AE Supply | Revolving | May 2018 | 2,500 | 2,489 |
| FET(2) | Revolving | May 2018 | 1,000 | — |
| | | Subtotal | $6,000 | $2,713 |
| | | Cash | — | 48 |
| | | Total | $6,000 | $2,761 |

(1) FE and the Utilities
(2) Includes FET, ATSI and TrAIL as subsidiary borrowers

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). The Facilities consist of a $2.5 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On October 31, 2013, FE amended its existing $2.5 billion multi-year syndicated revolving credit facility to exclude certain after-tax, non-cash write-downs and non-cash charges of approximately $1.4 billion (primarily related to Pension and OPEB mark-to-market adjustments, impairment of long-lived assets and regulatory charges) from the debt to total capitalization ratio calculations incurred through September 30, 2013. Additionally, the amendment provides for a future allowance of approximately $1.35 billion for after-tax, non-cash write-downs and non-cash charges over the remaining life of the facility. Similarly, the FES/AE Supply $2.5 billion revolving credit facility was also amended to exclude certain similar after-tax, non-cash write-downs and non-cash charges of $785.7 million incurred through September 30, 2013 from the debt to total capitalization ratio calculations. As of December 31, 2013, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, 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, 2013:

| Borrower | Revolving Credit Facility Sub-Limits | Regulatory and Other Short-Term Debt Limitations | |
|---|---|---|---|
| | (In millions) | | |
| FE | $2,500 | $— | (1) |
| FES | 1,500 | — | (2) |
| AE Supply | 1,000 | — | (2) |
| FET | 1,000 | — | (1) |
| OE | 500 | 500 | (3) |
| CEI | 500 | 500 | (3) |
| TE | 500 | 500 | (3) |
| JCP&L | 600 | 850 | (3) |
| ME | 300 | 500 | (3) |
| PN | 300 | 300 | (3) |
| WP | 200 | 200 | (3) |
| MP | 150 | 500 | (3) |
| PE | 150 | 150 | (3) |
| ATSI | 100 | 500 | (3) |
| Penn | 50 | 50 | (3) |
| TrAIL | 200 | 400 | (3) |

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

Term Loan

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings during 2013 was 0.67% per annum for the regulated companies' money pool and 1.34% per annum for the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2013 and 2012, were as follows:

| | 2013 | 2012 |
|---|---|---|
| FirstEnergy | 1.80% | 1.97% |

14. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.
FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2013 and 2012 were as follows:

| | 2013 | 2012 |
|---|---|---|
| | (In millions) | |
| FirstEnergy | $2,201 | $2,204 |
| FES | $1,276 | $1,283 |

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

The following table summarizes the changes to the ARO balances during 2013 and 2012:

| ARO Reconciliation | FirstEnergy | FES |
|---|---|---|
| | (In millions) | |
| Balance, January 1, 2012 | $1,497 | $904 |
| Liabilities settled | (2) | (1) |
| Accretion | 104 | 62 |
| Balance, December 31, 2012 | $1,599 | $965 |

| | | |
|---|---|---|
| Liabilities settled | (18) | (18) |
| Accretion | 115 | 71 |
| Revisions in estimated cash flows | (18) | (3) |
| Balance, December 31, 2013 | $1,678 | $1,015 |

During 2013, revisions to estimated cash flows as a result of increased cost estimates for the closure of LBR increased the associated ARO liability of FES by $163 million. The revised cost estimates were the result of a Closure Plan submitted to the PA DEP by FG on March 28, 2013, which provides for placing a final cap over LBR, and a response to a technical deficiency letter issued by the PA DEP on October 3, 2013. See Note 16, Commitments, Guarantees, and Contingencies for additional information related to the closure of LBR.

During the third quarter of 2013, studies were completed to update the estimated cost of asbestos remediation for FES and TE. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES and TE and increased the liability for FES and TE by approximately $5 million and $7 million, respectively.

During the fourth quarter of 2013, revisions to estimated nuclear decommissioning cash flows associated with the ARO liability of FES, OE and TE decreased the liability by $171 million, $15 million and $7 million, respectively. The revision in estimates for the ARO balances is the result of a decommissioning study that was completed by a third-party in connection with Davis-Besse’s license renewal that was submitted to the NRC in February 2014. The most significant revision from this study was related to accelerating the expected date when the DOE would begin to accept spent fuel, to be more in line with the industry assumptions. Additionally, FirstEnergy also updated and revised its estimates for Perry and Beaver Valley Units 1 and 2, in a consistent manner.

## 15. REGULATORY MATTERS

### STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

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

### MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by May 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On November 15, 2013, the Division of Rate Counsel filed testimony recommending that approximately $15 million of JCP&L’s costs be disallowed for recovery. Evidentiary hearings in this proceeding were scheduled for January 2014 but were subsequently adjourned by the NJBPU before their commencement. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L’s $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;

- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on February 24, 2014.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Ohio Companies recently reported that they met all of their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. Hearings on the plans are scheduled to be held March 4-7, 2014. The Pennsylvania Companies expect a decision from the PPUC by August 4, 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC’s motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court’s decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies'

PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ’s decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The Office of Consumer Advocate took exception to one issue and both parties filed replies to exceptions on December 12, 2013. The case is now before the PPUC for consideration.
A decision is expected during the first quarter of 2014.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed but the WVPSC has not yet issued an opinion in this matter.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. The charge is included in Impairment of long lived assets within the Consolidated Statement of Income. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. In accordance with the settlement, MP and PE will file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the West Virginia Supreme Court. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. Oral argument before the Supreme Court is scheduled for March 5, 2014.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision 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 (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated for briefing and disposition before that court. Briefing is complete, and the case will be scheduled for oral argument, with a decision currently expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including

FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's separate Order No. 1000 compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, have sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing was completed in December 2013 and oral argument is scheduled for March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility of certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone for the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs to the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In the May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. The case thereafter was briefed and oral arguments took place on December 11, 2013. A decision currently is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy’s subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. See Note 20, Discontinued Operations and Assets Held for Sale for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, in January 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the “joint and common market” stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $65.5 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FES and AE Supply's request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into three categories: (i) Demand Response (DR); (ii) imports; and (iii) modeling of transmission upgrades in calculating geographic clearing prices. The purpose of PJM’s tariff amendments is to ensure that resources that clear in the RPM auctions are available and able to satisfy all obligations under the PJM tariffs. In each of the affected dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The

FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC issued deficiency letters requesting additional information from PJM regarding the imports and modeling filings, and on January 30, 2014 accepted the DR filing as proposed. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling and imports filings. PJM's compliance filings and all other filings in the dockets are pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

16. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (OE-$44 million, NG-$442 million, and TE-$23 million) per incident but not more than $76 million (OE-$7 million, NG-$66 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $2 billion (OE-$168 million, NG-$1.7 billion, TE-$90 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $14 million (OE-$1.2 million, NG-$12 million and TE-$0.6 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $79 million (OE-$7 million, NG-$68 million, TE-$3 million and ME-$1 million).

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

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of December 31, 2013, outstanding guarantees and other assurances aggregated approximately $4.3 billion, consisting of parental guarantees ($1,375 million), subsidiaries' guarantees ($2,197 million) and other guarantees ($742 million).

Of this amount, substantially all relates to guarantees of wholly-owned consolidated entities. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2013, FES has posted collateral of $142 million and AE supply has posted collateral of $8 million. The Regulated Distribution segment has posted collateral of $11 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2013:

| Collateral Provisions | FES | AE Supply | Utilities | Total |
|---|---|---|---|---|
| | (In millions) | | | |
| Split Rating (One rating agency's rating below investment grade) | $496 | $6 | $53 | $555 |
| BB+/Ba1 Credit Ratings | $542 | $6 | $53 | $601 |
| Full impact of credit contingent contractual obligations | $777 | $58 | $88 | $923 |

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and Competitive Energy Services segment. As of December 31, 2013, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $66 million and $2 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the new facility.

In connection with the current facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the current facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility no later than July 20, 2015, which reflects the terms of an amendment dated August 14, 2013, on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global

Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1, 2013 through October 18, 2015, which amends the rate in the prior agreement, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

ENVIRONMENTAL MATTERS

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

CAA Compliance

FirstEnergy is required to meet federally-approved $SO_2$ and NOx emissions regulations under the CAA. FirstEnergy complies with $SO_2$ and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which affirmed the dismissal on August 21, 2013 and then denied petitions for rehearing on December 12, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, and the Allegheny Utilities finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and $SO_2$ emissions in two phases (2009/2010 and 2015), ultimately capping $SO_2$ emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but 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 decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and $SO_2$ emissions in two phases (2012 and 2014), ultimately capping $SO_2$ emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and $SO_2$ emission allowances between power plants located in the same state and interstate trading of NOx and $SO_2$ emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the D.C. Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR and heard oral argument on December 10, 2013. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS has been challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. Oral arguments were heard on December 10, 2013. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payments of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including the EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of $CO_2$ equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard of 1,000 lbs. $CO_2$/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. $CO_2$/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. $CO_2$/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including $CO_2$, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting $CO_2$ emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The $CO_2$ emissions per KWH of electricity generated by FirstEnergy is lower than many of its 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 CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. The period for finalizing the Section 316(b) regulation was extended to April 17, 2014 under a Settlement Agreement between EPA and certain NGOs. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its asset retirement obligation for LBR by $163 million in 2013. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.