ANNUAL 2015 REPORT

FirstEnergy®

FINANCIAL HIGHLIGHTS

KEY ACCOMPLISHMENTS

- Generated $3.4 billion in cash from operations
- Invested nearly $1 billion to modernize our transmission system as part of our Energizing the Future initiative
- Launched our Cash Flow Improvement Project with the goal of capturing meaningful and sustainable savings across our company
- Secured a 20-year license extension from the Nuclear Regulatory Commission for the Davis-Besse Nuclear Power Station
- Enhanced transmission and distribution system reliability

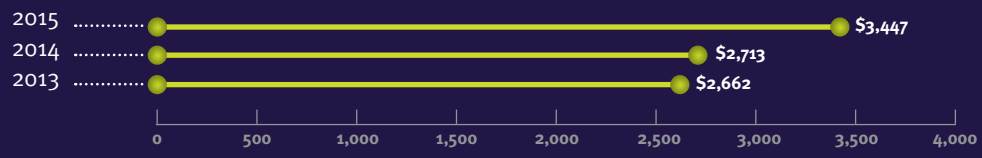
FINANCIALS AT A GLANCE

(dollars in millions, except per share amounts)

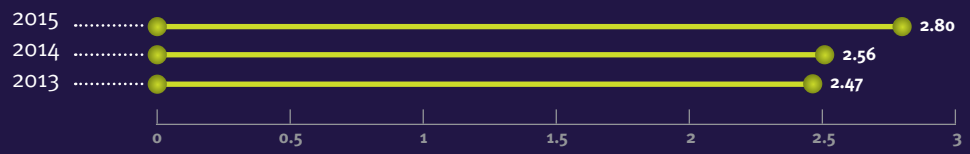
	2015	2014	2013
TOTAL REVENUES	$15,026	$15,049	$14,892
NET INCOME	$578	$299	$392
BASIC AND DILUTED EARNINGS per common share	$1.37	$0.71	$0.94
DIVIDENDS PAID per common share	$1.44	$1.44	$2.20
BOOK VALUE per common share	$29.33	$29.49	$30.32

NET CASH FROM OPERATING ACTIVITIES

(in millions)



TRANSMISSION AND DISTRIBUTION RELIABILITY INDEX*



NET INCOME

(in millions)

*FirstEnergy's index comprises two indices that are commonly used in the electric utility industry: Transmission Outage Frequency (TOF) and System Average Interruption Duration Index (SAIDI). Our index measures frequency and duration of service interruptions: the better the performance, the higher the score.

Charles E. Jones
President and Chief Executive Officer

A MESSAGE TO OUR SHAREHOLDERS

We maintained a strong focus in 2015 on achieving more regulated, customer-focused growth for your company.

Toward that end, we made significant investments to enhance the reliability and efficiency of our electric system. These included $986 million in targeted improvements during the year to our transmission system, and approximately $1.2 billion in capital upgrades that helped our regulated utilities continue to provide reliable service to customers. We also received approval on a forward-looking rate filing for our American Transmission Systems, Inc. (ATSI) transmission company, which will allow more effective and timely recovery of its system investments.

Six of our regulated utilities received approval of settlements in distribution rate cases in 2015, and our rate case in New Jersey also was resolved, resulting in an overall revenue increase of $321 million. In Ohio, the Public Utilities Commission of Ohio (PUCO) is reviewing a settlement agreement with 17 key parties supporting our Electric Security Plan IV (ESP) for The Illuminating Company, Ohio Edison and Toledo Edison. The plan is expected to strengthen your company's financial position in the years ahead and is designed to provide significant benefits to our customers and communities – including more stable rates, a renewed emphasis on energy efficiency and renewable power, and strong support for economic development. The PUCO is expected to rule on the ESP by the end of March.

We also expect to achieve $240 million in annual savings by 2017 through our Cash Flow Improvement Project – a comprehensive effort our employees conducted in 2015, and will closely monitor in the years ahead, to reduce expenses and enhance revenue throughout our operations. In addition, we continue to execute a more conservative strategy for our competitive generation business that minimizes risk while taking advantage of market opportunities.

GROWING OUR

REGULATED OPERATIONS

We're building a stronger energy system through our primary growth platform, Energizing the Future – an initial $4.2 billion investment in the long-term reliability of our transmission system that began in 2014 and runs through 2017. Spanning our entire transmission system, projects funded through the program are designed to meet the future energy needs of customers by adding resiliency to our bulk electric system, enhancing our facilities and equipment, and increasing physical and cyber security.

Initial efforts primarily focused on the ATSI transmission system that encompasses the service areas of Ohio Edison, Toledo Edison, The Illuminating Company and Penn Power, with projects shifting eastward over time to include our other service areas. Work performed to date also has helped us identify $15 billion in additional opportunities across our 24,200-mile transmission system that will benefit customers through further reliability enhancements.

Among other projects, we're reinforcing our system to ensure grid reliability following the retirement of coal-fired power plants in our region. For example, since 2014, we've invested $500 million in transmission projects to support the deactivation of three of our power plants along Lake Erie. As part of this effort, we built a 119-mile transmission line from Beaver County, Pa., to our new Glenwillow substation in suburban Cleveland, as well as five new substations across portions of our Ohio service area.

In addition, we're nearing completion of a transmission reinforcement project in Harrison County, W.Va., that involves the construction of a new substation and a 6-mile transmission line. The project is expected to enhance service reliability for approximately 14,000 customers in the northern portion of West Virginia.

Given that our regulated footprint is aligned with some of the nation's richest shale fields, we're making investments through 2020 to support growth in midstream shale gas operations throughout our service area, including planned expansions that are expected to create 600 megawatts (MW) of new industrial load. For example, we recently completed preliminary site work for a new substation near Smithfield, W.Va., that is expected to support new shale gas operations as well as enhanced service reliability for Mon Power customers. Over the past few years, shale gas development has accounted for approximately 500 MW of new load growth in our region.

We remain committed to providing safe, reliable service to our utility customers. All of our utilities outperformed state requirements for SAIDI – an industry-wide measure of the average outage duration for each customer served.

In the critical area of safety, our companywide OSHA rate reached industry top-quartile performance in 2015. This reflects the great importance we place on safe work practices in every facet of our operations.

A crew member welds a stainless steel roof for one of three, 1 million-gallon water tanks for the dewatering facility under construction at our Bruce Mansfield Plant. The facility is needed to dispose of the plant's coal combustion byproducts following the scheduled closing of the Little Blue Run disposal site at the end of 2016.

CREATING A SMARTER GRID

As part of our Energizing the Future initiative, we began investing in nearly 900 smart grid projects designed to make our transmission system more robust, secure and resistant to extreme weather events as well as cyber and physical attacks.

These smart grid technologies have the potential to significantly improve our response time to outages by enabling more efficient service restoration. In addition, remote monitoring devices can proactively evaluate grid conditions and take corrective actions even before outages occur. We're also upgrading our transmission equipment with advanced technologies designed to enhance the reliability of our system and meet projected load growth in our region.

We continued to move forward with our Pennsylvania smart meter program, installing more than 160,000 smart meters in our Penn Power service area by the end of 2015. Through this state-mandated effort, we plan to deploy more than 2 million smart meters across our Pennsylvania service area by mid-2019.

Although smart grid technologies can be costly, we're receiving full recovery of our investments in Pennsylvania's smart meter program – and we will explore similar programs in other states that allow recovery of these costs. In fact, as part of our proposed ESP, we filed a plan to evaluate smart meter and smart grid technologies across our Ohio service area, subject to PUCO consideration and approval.

NEARLY
32 MILLION
MEGAWATT-HOURS OF CARBON-FREE ELECTRICITY GENERATED BY OUR THREE NUCLEAR POWER STATIONS IN 2015

ENSURING FAIR AND

AFFORDABLE RATES

We made significant progress during the year in our efforts to strengthen earnings by ensuring fair, appropriate and timely recovery of our transmission and distribution investments.

In October, the Federal Energy Regulatory Commission (FERC) approved a settlement agreement for a forward-looking rate structure for ATSI, which owns and operates nearly 7,800 miles of transmission lines. This agreement provides more timely recovery of transmission investments that are essential to ensuring the future reliability of our service.

FERC also approved a plan to transfer the transmission assets owned by three of our operating companies – Jersey Central Power & Light (JCP&L), Met-Ed and Penelec – to a new affiliate, Mid-Atlantic Interstate Transmission (MAIT). Similar to our existing ATSI and TrAILCo transmission companies, MAIT will help us more effectively finance and build transmission facilities within our Met-Ed, Penelec and JCP&L service areas while providing stronger support to our Energizing the Future initiative as it expands eastward. Although the New Jersey Board of Public Utilities (BPU) rejected one of the plan's provisions, it continues to review the remainder of the proposal. We also filed a comprehensive settlement agreement with the Pennsylvania Public Utility Commission (PPUC) for approval of MAIT.

Approval of our Ohio ESP by the PUCO would be an important step in our efforts to protect customers from future price volatility. The plan includes a rider that reflects the difference between the cost of an eight-year Purchased Power Agreement (PPA) and our Ohio utilities' associated wholesale market revenues. The PPA supports the continued operation of two of our critical baseload power plants – the Davis-Besse Nuclear Power Station and the W.H. Sammis Plant – which would preserve more than $41 million in annual tax revenues and an estimated 3,000 direct and indirect jobs related to those facilities. Although the PPA has been challenged at FERC, we will continue to advocate for the plan's many benefits in that proceeding.

In February of 2016, the PPUC approved long-term infrastructure improvement plans for our four Pennsylvania utilities, supporting a projected increase in capital investment of nearly $245 million over the next five years to strengthen, upgrade and modernize our distribution systems in the state. The four utilities also filed rate riders that, with PPUC approval, would facilitate recovery of these investments.

Our competitive subsidiary, FirstEnergy Solutions, contracts for renewable energy from the 35-MW Casselman Wind Power Project located in Somerset County, Pa.

PROVIDE MORE THAN
1 MILLION
MEGAWATT-HOURS PER YEAR
OF WIND GENERATION

LOWERING RISK IN OUR

COMPETITIVE BUSINESS

We continue to execute a conservative sales and generation strategy that offers less risk to the company.

To achieve this goal, our FirstEnergy Solutions subsidiary continued to restructure its sales portfolio to reduce our exposure to weather-sensitive demand and ensure we don't sell more power than we produce. A larger portion of our generation is kept in reserve to minimize our financial risk when energy prices increase and ensure power is available to sell when market conditions are favorable.

We're maintaining our support of governmental aggregation and other higher-margin sales while pursuing wholesale opportunities that align with our generation portfolio. We also remain committed to economically dispatching our fleet and operating our units with greater flexibility.

FirstEnergy Nuclear Operating Company (FENOC) reached a significant milestone in 2015 when the Nuclear Regulatory Commission approved a 20-year license extension for the Davis-Besse Nuclear Power Station, allowing the unit to operate until 2037. In addition, improved reliability and outage execution enabled FENOC to produce approximately 1 million megawatt-hours over its original plan for the year, further improving commodity margin.

PJM Interconnection's new Capacity Performance product had a positive impact in more properly valuing essential and highly reliable baseload generating resources. Capacity auctions held in August and September of 2015 are expected to improve revenues by $1.1 billion from June 2016 through May 2019. However, markets continue to fall short of reflecting the true cost of operating our baseload power plants.

MEETING OUR ENVIRONMENTAL

COMMITMENTS

In 2015, we continued to make progress to improve the environmental performance of our operations.

Our proposed Ohio ESP includes a goal to reduce carbon dioxide emissions by at least 90 percent below 2005 levels by 2045 – exceeding President Obama's goal of achieving economywide reductions of 80 percent or more by 2050.

The Clean Power Plan called for individual states to develop plans for meeting the U.S. Environmental Protection Agency's state-specific emission reduction goals. However, on Feb. 9, 2016, the U.S. Supreme Court granted a petition from 27 states and other stakeholders to halt enforcement of the Clean Power Plan's final rule until after all legal challenges are resolved.

FirstEnergy submitted extensive comments before the rule was finalized, and we're continuing to engage federal and state policymakers on issues related to our ongoing efforts to ensure the availability of clean, reliable and affordable energy resources for customers.

We've also made the significant investments needed to comply with the EPA's Mercury and Air Toxics Standards and other requirements, and we will continue to invest in our fossil fleet to help maintain reliable and affordable supplies of power for customers as we make the transition to a cleaner energy future.

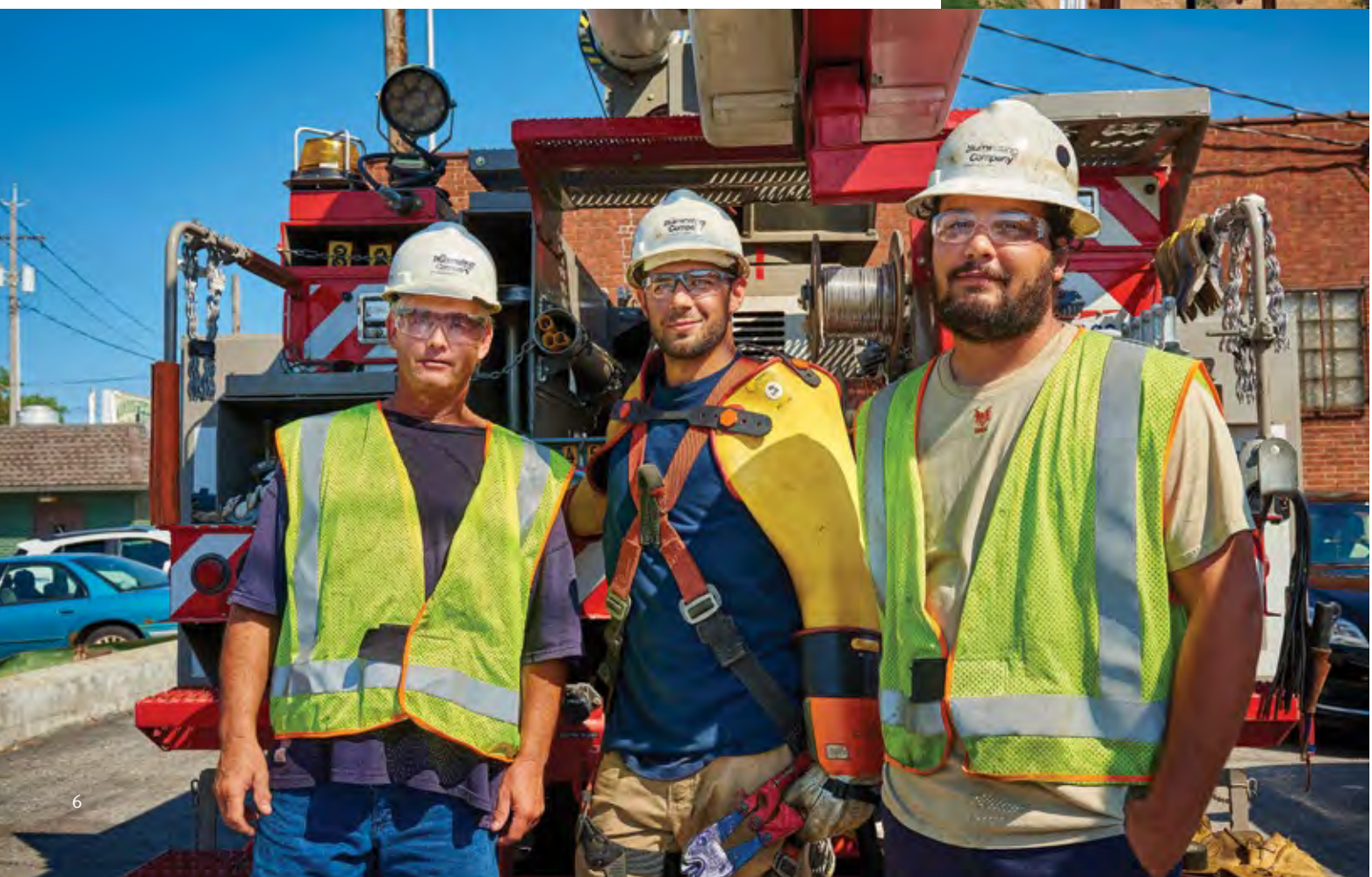
SETTING A COURSE FOR THE FUTURE

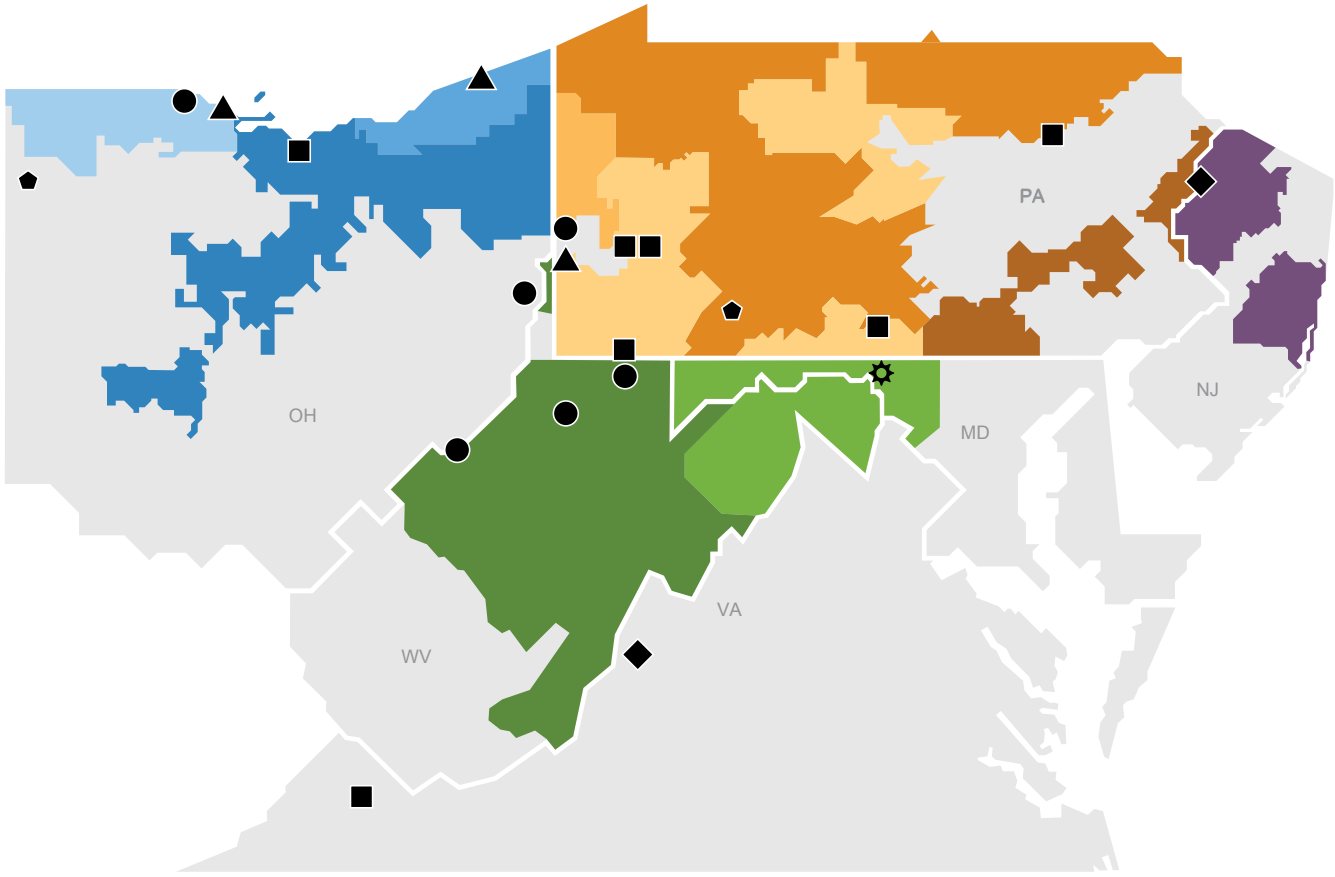
I'm proud of what our employees have accomplished, and I'm confident they will help us succeed in the future by continuing to provide customers with the level of service they expect and deserve.

We're pursuing the right strategy for your company. By achieving solid performance across our three business sectors – distribution, transmission and generation – and remaining focused on meeting our customers' immediate and long-term energy needs, we can deliver more sustainable growth and greater financial stability for FirstEnergy in the years ahead.

Thank you for your support as we work to achieve continued success for your company.

Charles E. Jones
President and Chief Executive Officer
March 16, 2016





CORPORATE PROFILE

Headquartered in Akron, Ohio, FirstEnergy is a leading regional energy provider dedicated to safety, operational excellence and responsive customer service. Our subsidiaries are involved in the generation, transmission and distribution of electricity.

Our 10 utility operating companies form one of the nation's largest investor-owned electric systems based on 6 million customers served within a nearly 65,000-square-mile area of Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York.

Our generation subsidiaries control nearly 17,000 megawatts (MW) of capacity from a diversified mix of scrubbed coal, nuclear, natural gas, oil, hydroelectric pumped-storage and contracted wind and solar resources – including 1,900 MW of renewable energy. The company's transmission subsidiaries operate approximately 24,200 miles of transmission lines connecting the Midwest and Mid-Atlantic regions.

FirstEnergy Solutions, our competitive subsidiary, is a retail energy supplier serving approximately 1.6 million residential, commercial and industrial customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan and Illinois.

Ohio
- Ohio Edison
- The Illuminating Company
- Toledo Edison

Pennsylvania
- Met-Ed
- Penelec
- Penn Power
- West Penn Power

West Virginia/Maryland
- Mon Power
- Potomac Edison

New Jersey
- Jersey Central Power & Light

Generating Stations
- Coal
- Gas/Oil
- Hydro
- Nuclear
- Wind
- Solar

FirstEnergy Board of Directors

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

Michael J. Anderson
Chairman of the Board of The Andersons, Inc. (diversified agribusiness).

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

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

Julia L. Johnson
President of NetCommunications, LLC (regulatory and public affairs firm).

Charles E. Jones
President and Chief Executive Officer of FirstEnergy Corp.

Ted J. Kleisner
Retired, formerly Chairman of the Board and Chief Executive Officer of Hershey Entertainment & Resorts Company.

Donald T. Misheff
Retired, formerly Managing Partner of the Northeast Ohio offices of Ernst & Young LLP.

Thomas N. Mitchell
Retired, formerly President, CEO and Director of Ontario Power Generation Inc.

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

Christopher D. Pappas
President and Chief Executive Officer of Trinseo S.A., formerly Styron LLC (plastics, latex and rubber producer).

Luis A. Reyes
Retired, formerly Regional Administrator of the U.S. Nuclear Regulatory Commission.

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

Dr. Jerry Sue Thornton
CEO of Dream Catcher Educational Consulting (higher education coaching and professional development). Retired President of Cuyahoga Community College.

Dear Shareholders:

FirstEnergy's management team and employees made significant progress in 2015. Your Board of Directors commends their efforts to achieve customer-focused growth in the company's regulated utility operations, manage risk in its competitive business, and reduce expenses.

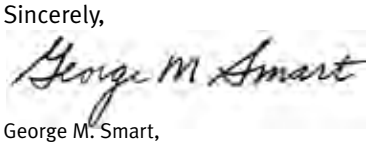
Your Board provided an annual dividend rate of $1.44 per share in 2015. As FirstEnergy addresses future opportunities and challenges, we will continue to review the dividend on a quarterly basis.

Your Board is committed to maintaining the appropriate practices and policies that help ensure good corporate governance. We also support your management team as it focuses on ensuring employee safety, providing outstanding service to customers, enhancing the company's environmental performance, and delivering consistent and predictable financial results.

I welcome Thomas N. Mitchell, who was elected to serve on the company's Board in January 2016. Tom is a well-respected nuclear industry veteran with 38 years of experience in the field, including leadership positions at the World Association of Nuclear Operators, the Institute of Nuclear Power Operations, the Nuclear Energy Institute and the Electric Power Research Institute.

Your Board remains dedicated to representing your interests and enhancing the value of your investment in FirstEnergy. Thank you for your ongoing support.

Sincerely,



George M. Smart,
Chairman of the Board

FirstEnergy Corp. Executive Officers*

Charles E. Jones
President and Chief Executive Officer

Leila L. Vespoli
Executive Vice President, Markets and Chief Legal Officer

James H. Lash
Executive Vice President and President, FE Generation

James F. Pearson
Executive Vice President and Chief Financial Officer

Gary D. Benz
Senior Vice President, Strategy

Lynn M. Cavalier
Chief Human Resource Officer

Dennis M. Chack
Senior Vice President, Marketing and Branding

Michael J. Dowling
Senior Vice President, External Affairs

Bennett L. Gaines
Senior Vice President, Corporate Services and Chief Information Officer

Charles D. Lasky
Senior Vice President, Human Resources

Donald R. Schneider
President, FirstEnergy Solutions

Steven E. Strah
Senior Vice President and President, FirstEnergy Utilities

K. Jon Taylor
Vice President, Controller and Chief Accounting Officer

*More detailed information on the principal occupation or employment of each of our executive officers and the principal business of any organization by which FirstEnergy Executive Officers are employed may be found on page 145 of this report.

2015
ANNUAL REPORT

CONTENTS

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, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, which provided legal, financial and other corporate support services to the former AE subsidiaries
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and equity method investee of MP
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, a subsidiary of AE Supply
Buchanan Generation	Buchanan Generation, LLC, a joint venture between AE Supply and CNX Gas Corporation
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FELHC, Inc.
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, 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 wholly-owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FGMUC	FirstEnergy Generation Mansfield Unit 1 Corp., a wholly-owned subsidiary of FG, which owns various leasehold interests in Bruce Mansfield Unit 1
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	Global Rail Group, LLC, 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 FE on November 7, 2001
Green Valley	Green Valley Hydro, LLC, which owned hydro generating stations
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate transmission facilities
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
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 FE and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland and West Virginia electric utility operating subsidiary
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	Signal Peak Energy, LLC, 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

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

AAA	American Arbitration Association
AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMT	Alternative Minimum Tax
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
ASU	Accounting Standards Update
BGS	Basic Generation Service
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CBA	Collective Bargaining Agreement
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFL	Compact Fluorescent Light
CFR	Code of Federal Regulations
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CONE	Cost-of-New-Entry
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EMAAC	Eastern Mid-Atlantic Area Council of PJM
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
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
ESTIP	Executive Short-Term Incentive Program
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board

FERC	Federal Energy Regulatory Commission
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
GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCl	HydroChloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICP 2007	FirstEnergy Corp. 2007 Incentive Plan
ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour
KPI	Key Performance Indicator
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LED	Light Emitting Diode
LMP	Locational Marginal Price
LOC	Letter of Credit
LSE	Load Serving Entity
LTIIPs	Long-Term Infrastructure Improvement Plans
MAAC	Mid-Atlantic Area Council of PJM
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master Limited Partnership
mmBTU	One Million British Thermal Units
Moody's	Moody's Investors Service, Inc.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator

NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
OPEB	Other Post-Employment Benefits
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
PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Purchase Power Agreement
PPB	Parts per Billion
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PTC	Price-to-Compare
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
Regulation FD	Regulation Fair Disclosure promulgated by the SEC
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROE	Return on Equity
RPM	Reliability Pricing Model
RRS	Retail Rate Stability
RSS	Rich Site Summary
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 No. 221
SB310	Substitute Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service

SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
TTS	Temporary Transaction Surcharge
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
VIE	Variable Interest Entity
VRR	Variable Resource Requirement
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2015	2014	2013	2012	2011
	(In millions, except per share amounts)				
Revenues	$ 15,026	$ 15,049	$ 14,892	$ 15,255	$ 16,087
Income From Continuing Operations	$ 578	$ 213	$ 375	$ 755	$ 856
Earnings Available to FirstEnergy Corp.	$ 578	$ 299	$ 392	$ 770	$ 885
Earnings per Share of Common Stock:					
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 1.81	$ 2.19
Basic - Discontinued Operations (Note 19)	—	0.20	0.04	0.04	0.03
Basic - Earnings Available to FirstEnergy Corp.	$ 1.37	$ 0.71	$ 0.94	$ 1.85	$ 2.22
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 1.80	$ 2.18
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04	0.04	0.03
Diluted - Earnings Available to FirstEnergy Corp.	$ 1.37	$ 0.71	$ 0.94	$ 1.84	$ 2.21
Weighted Average Shares Outstanding:					
Basic	422	420	418	418	399
Diluted	424	421	419	419	401
Dividends Declared per Share of Common Stock	$ 1.44	$ 1.44	$ 1.65	$ 2.20	$ 2.20
Total Assets[(1)]	$ 52,187	$ 51,648	$ 50,058	$ 50,175	$ 47,410
Capitalization as of December 31:					
Total Equity	$ 12,422	$ 12,422	$ 12,695	$ 13,093	$ 13,299
Long-Term Debt and Other Long-Term Obligations	19,192	19,176	15,831	15,179	15,716
Total Capitalization	$ 31,614	$ 31,598	$ 28,526	$ 28,272	$ 29,015

[(1)]Reflects the application of ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which requires all accumulated deferred income taxes to be classified as non-current. The retrospective change decreased Total Assets as of December 31 as follows: 2014 - $518 million, 2013 -$366 million, 2012 - $319 million as these amounts were reclassified from current assets to non-current liabilities.

PRICE RANGE OF COMMON STOCK

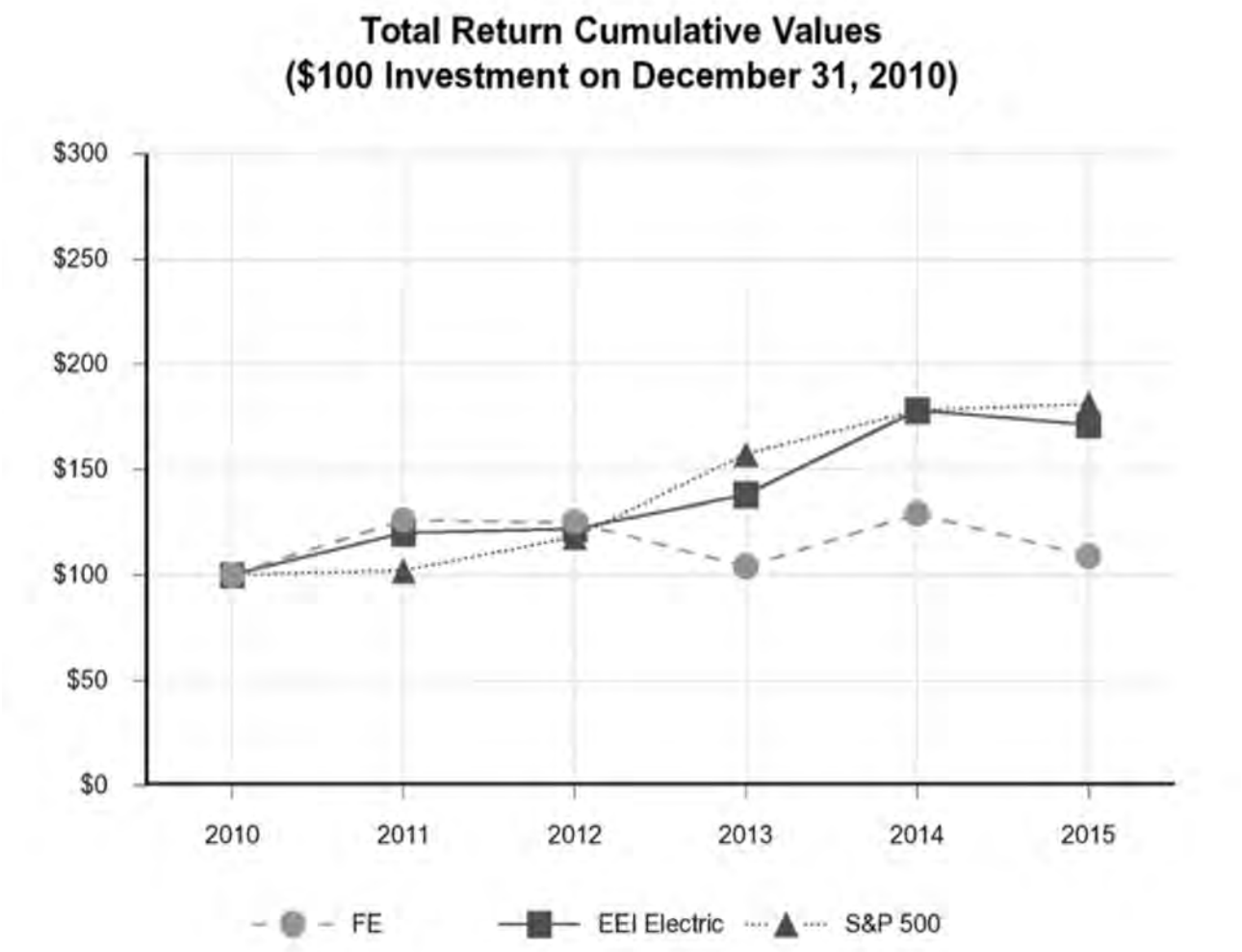
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol “FE” and is traded on other registered exchanges.

	2015		2014	
	High	Low	High	Low
First Quarter	$ 41.68	$ 33.82	$ 34.28	$ 30.10
Second Quarter	$ 37.05	$ 32.46	$ 35.59	$ 31.17
Third Quarter	$ 35.09	$ 30.31	$ 34.95	$ 29.98
Fourth Quarter	$ 33.00	$ 28.89	$ 40.84	$ 33.04
Yearly	$ 41.68	$ 28.89	$ 40.84	$ 29.98

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, 2010 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 90,633 and 90,346 holders of 423,560,397 and 423,650,645 shares of FirstEnergy's common stock as of December 31, 2015 and January 31, 2016, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11, Capitalization of the Combined Notes to Consolidated Financial Statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT AND SUBSIDIARIES

Forward-Looking Statements: This report includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "forecast," "target," "will," "intend," "believe," "project," "estimate," "plan" 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, which may include the following:

- 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 successfully implement our sales strategy for the CES segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including but not limited to, the proposed transmission asset transfer to MAIT, and the effectiveness of our strategy to reflect a more regulated business profile.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities.
- The impact of the regulatory process on the pending matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and the ESP IV in Ohio.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates, including FERC Opinion No. 531's revised ROE methodology for FERC-jurisdictional wholesale generation and transmission utility service; and FERC's compliance and enforcement activity, including compliance and enforcement activity related to NERC's mandatory reliability standards.
- 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 a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil prices, and their availability and impact on margins and asset valuations.
- 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, but not limited to, the effects of the EPA's CPP, CCR, CSAPR and MATS programs, including our estimated costs of compliance, CWA waste water effluent limitations for power plants, and CWA 316(b) water intake regulation.
- 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 initiatives or rulemakings 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 as it relates to the reliability of the transmission grid, the timing thereof.
- The impact of other future changes to the operational status or availability of our generating units and any capacity performance charges associated with unit unavailability.
- 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 at Davis-Besse.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- The impact of labor disruptions by our unionized workforce.
- 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 continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our cash flow improvement plan and other proposed capital raising 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/or 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 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/or 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/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- 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 associated with cyber-attacks and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks.
- 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.

These forward looking statements are also qualified by, and should be read together with, the risk factors included in (a) Item 1A. Risk Factors of our Annual Report on Form 10-K filed with the SEC on February 16, 2016, (b) this Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in other filings with the SEC by FE. The foregoing review of factors also 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.

FIRSTENERGY'S BUSINESS

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission, and CES.

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 located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 3,790 MWs of generation capacity.

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

Company	Area Served	Customers Served [1]
OE	Central and Northeastern Ohio	1,038
Penn	Western Pennsylvania	164
CEI	Northeastern Ohio	746
TE	Northwestern Ohio	308
JCP&L	Northern, Western and East Central New Jersey	1,109
ME	Eastern Pennsylvania	561
PN	Western Pennsylvania	588
WP	Southwest, South Central and Northern Pennsylvania	723
MP	Northern, Central and Southeastern West Virginia	390
PE	Western Maryland and Eastern West Virginia	401
		6,028

[1] As of December 31, 2015

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). This segment also includes 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 primarily from transmission services provided pursuant to its PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The **CES** segment, through FES and AE Supply, primarily 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 13,162 MWs of capacity. The CES 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 and capacity costs charged by PJM to deliver energy to the segment's customers.

The CES segment expects to sell its annual generation output of approximately 75 to 80 million MWHs, with up to an additional 5 million MWHs available from PPAs for wind, solar and its entitlement from OVEC, through a target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct), 10 to 20 million MWHs in block wholesale sales, including Structured Sales, and 10 to 20 million MWHs of spot wholesale sales.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

FirstEnergy continues to capitalize on investment opportunities available in its Regulated Transmission and Regulated Distribution businesses while implementing a conservative hedging strategy at its Competitive business. FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at each business unit, while improving metrics at FirstEnergy over time.

FirstEnergy's regulated investment strategy focuses on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure. Focusing on reinvestment in its regulated operations will also provide stability and growth for FirstEnergy as this plan is implemented over the coming years.

Regulated Transmission

The centerpiece of FirstEnergy's regulated investment strategy is the *Energizing the Future* transmission expansion plan. The initial phase of this plan includes $4.2 billion in investments from 2014 through 2017 to modernize FirstEnergy's transmission system.

In conjunction with its transmission expansion plan, in 2015 ATSI received FERC-approval of its "forward looking" rate, implemented on January 1, 2015, where transmission rates are based on estimated costs for the current year with an annual true up, and an ROE of: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and 10.38% effective January 1, 2016, unless changed pursuant to Section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Additionally, in June 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. If approved, MAIT will operate similar to FET's two existing stand-alone transmission subsidiaries ATSI and TrAIL. FERC approval is expected in March 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

Regulated Distribution

During 2015, FirstEnergy continued to pursue key regulatory initiatives across its utility footprint, focusing on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives included:

- The Ohio Companies' ESP IV, *Powering Ohio's Progress:* The ESP IV, including the impact of filed stipulations in the case, contemplates continuing a distribution rate freeze through May 2024 while helping ensure continued availability of more than 3,200 MWs of FirstEnergy's critical baseload generating assets primarily located in the state and serving the long-term energy needs of Ohio customers. Evidentiary hearings commenced in August 2015. On December 1, 2015, FirstEnergy's Ohio Companies filed an additional settlement at the PUCO, which included the PUCO Staff as a signatory party, that sets forth ambitious steps to help safeguard customers against retail generation price increases in future years, deploy new energy efficiency programs, and provide a clear path to a cleaner energy future by establishing a goal to substantially reduce carbon emissions. The settlement includes an eight-year rate provision (Rider RRS) designed to help protect customers against rising retail price increases and market volatility, while helping preserve vital baseload power plants that serve Ohio customers and provide thousands of family-sustaining jobs in the state. The plants involved include the Davis-Besse Nuclear Power Station, the W.H. Sammis Plant, and a portion of the output of OVEC units in Gallipolis, Ohio, and Madison, Indiana. A decision is anticipated in March 2016. On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge, in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

- Implementation of New Rates in Pennsylvania for ME, PN, Penn and WP: The new rates were approved in April 2015 and went into effect in May 2015, providing for an increase in annual revenues of approximately $293 million and approximately $88 million of additional annual operating expenses. Furthermore, in October 2015, the Pennsylvania companies filed LTIIPs with the PPUC for infrastructure improvements over the 2016 to 2020 period totaling nearly $245 million, which were approved on February 11, 2016. The Pennsylvania Companies filed DSIC riders on February 16, 2016, for quarterly cost recovery associated with the projects approved in the LTIIPs.

- Implementation of New Rates in West Virginia for MP and PE: The new rates were approved and went into effect in February 2015, resulting in recovery of $63 million annually for reliability investments and expenses, storm damage expenses, and investments in operating improvements and environmental compliance at MP's and PE's regulated coal-fired power plants in West Virginia. MP and PE also received orders in December 2015 in their ENEC case and their biennial vegetation management program surcharge reconciliation, resulting in revenue increases, effective January 1, 2016, totaling $96.9 million and $36.7 million, respectively, to recover deferred costs.

Additionally, during 2015, the NJBPU issued orders on JCP&L's base rate proceedings and its generic storm proceedings resulting in a reduction of approximately $34 million in annual revenues, inclusive of recovery of 2011 and 2012 storm costs, as well as the NJBPU's recently modified CTA policy. As part of the base rate order, JCP&L is required to file another base rate case no later than April 1, 2017.

Competitive Energy Services

FirstEnergy continues its strategy for its competitive business to more effectively hedge its generation by reducing exposure to weather-sensitive load in certain sales channels and pursuing high-margin sales, while leaving a portion of its generation available to capture future market opportunities or to mitigate risk. This strategy is designed to position CES to benefit from opportunities as markets improve while limiting risk from continued challenging market conditions. At the same time, FirstEnergy continues to advocate for reforms that can ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability.

The CES 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. On average, the CES segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs available from purchased power agreements for wind, solar and its entitlement from OVEC. In 2015, CES sold approximately 75 million MWHs of which 68 million MWHs were through contract sales with another 7 million MWHs of wholesale sales. As of December 31, 2015, committed sales for 2016 and 2017 were approximately 61 million MWHs and 38 million MWHs, respectively.

From a generation perspective, FirstEnergy continues to focus on ensuring its competitive fleet is cost-effective, efficient and environmentally sound. FirstEnergy is on track to exceed benchmarks established by MATS and other environmental regulations. FirstEnergy's total cost for MATS compliance is expected to be approximately $345 million ($168 million at CES and $177 million at Regulated Distribution), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

During 2015, FirstEnergy completed scheduled shutdowns for three of its nuclear units - Beaver Valley Unit 1 and Unit 2 and the Perry Nuclear Power plant - for refueling and maintenance. During the outages, fuel assemblies were exchanged and numerous inspections and preventative maintenance and improvement projects were completed to ensure continued safe and reliable operations. Additionally, in December 2015, the NRC approved a 20-year license extension for the Davis-Besse Nuclear Power Station allowing the unit to operate until 2037.

Also, in 2015, PJM conducted the 2015 BRA for the 2018/2019 delivery year and Capacity Performance transition auctions for the 2016/2017 and 2017/2018 delivery years. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

Projected CES Capacity Revenue* ($ Millions)

	2016	2017	2018	2019 (through 5/31)
Capacity Revenue	$815	$590	$620	$260

*Includes revenues from the results of incremental/transitional capacity auctions, bilateral transactions and capacity transfer rights.

STRATEGY AND OUTLOOK

FirstEnergy owns a large and diverse mix of assets managed in an integrated model, featuring an electric distribution service area and transmission footprint that are among the largest in the nation, as well as a competitive operations segment that owns or controls over 13,000 MWs of generation with a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy continues to focus on developing its transmission business, strengthening its regulated utilities, and managing overall risk and conservatively operating its competitive business.

FirstEnergy continues to focus on investment opportunities in its Regulated Transmission and Regulated Distribution segments. This investment strategy is focused on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure. FirstEnergy expects to fund these investments through a combination of cash from operations, debt, and, depending on the regulated operating company, capital contributions from its parent. In the future, FirstEnergy may consider additional equity to fund capital requirements in its regulated operations.

FirstEnergy's longer term strategic outlook for its regulated and competitive businesses will be determined following resolution of the Ohio Companies' ESP IV, including the proposed PPA between FES and the Ohio Companies. Once the ESP IV is finalized, FirstEnergy expects to be in a position to more fully understand the longer-term outlook of its competitive businesses and the longer term growth rate of its regulated businesses, including planned capital investments and any additional equity to fund growth in its regulated businesses.

FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at each business unit, while improving metrics at FirstEnergy Corp. over time. As part of an ongoing effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three-year period.

Regulated Transmission

As noted above, the centerpiece of FirstEnergy's growth strategy is a $4.2 billion investment in the *Energizing the Future* program from 2014 through 2017. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. This program is focused on a large number of small projects within the company's 24,000 mile service territory that improve service to customers. The projects within the program are either regulatory required or support reliability enhancement. Regulatory required projects include those requested by PJM to support grid reliability, generator deactivations, or shale gas expansion activities. The second category of projects, those that support reliability enhancement, focus on replacing aging equipment; increasing automation, communication, and security within the system; and increasing load serving capability. In the initial years of the program, the majority of the projects are located within the ATSI system, with expectations to move east across FirstEnergy's service territory over time. An additional $15 billion in transmission investment opportunities have been identified across the system beyond the 2014-2017 period, making this a continuing and sustainable platform for investment.

In 2016, FirstEnergy expects to receive approval to transfer transmission assets of JCP&L, Met-Ed and Penelec to MAIT, a new stand-alone transmission subsidiary.

Regulated Distribution

The five-state service territory served by FirstEnergy's Regulated Distribution segment also offers substantial opportunities for future investments to improve service to more than 6 million customers. In 2015, FirstEnergy completed major rate cases in West Virginia, Pennsylvania and New Jersey. In Pennsylvania, a filing for an infrastructure improvement plan that includes an investment of $245 million through 2020 was approved by the PPUC on February 11, 2016, and in Ohio, a comprehensive settlement in the ESP IV is pending PUCO approval. The ESP IV settlement contains additional opportunities for investment in the Ohio Companies, including grid modernization and energy efficiency as well as continuation of Rider DCR with revenue caps increasing $180 million over the term of the ESP IV. The settlement also includes a FERC-jurisdictional PPA where the Ohio Companies would purchase the output from FES' Davis-Besse nuclear plant, Sammis coal plant and entitlement to OVEC generation output, a total of 3,244 MW, for an eight-year term beginning June 1, 2016.

FirstEnergy also continues to closely monitor sales trends across its utility footprint. Within its Regulated Distribution segment, FirstEnergy continues to be impacted by lower customer usage as a result of energy efficiency mandates and products. During 2015, electric distribution deliveries on a weather-adjusted basis declined 1.6% in the residential customer class and 0.6% in the commercial customer class as compared to 2014. Furthermore, in the industrial sector, increases in the shale gas sector were more than offset with lower usage in the steel and mining sectors, resulting in an overall decrease in the industrial sector of 2.0%.

CES

FirstEnergy continues to focus on maintaining the value of its competitive business and continues to advocate for reforms that ensure the competitive wholesale markets adequately value baseload generation, which is essential for maintaining grid reliability. While it cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last several years to reposition this business for such a recovery. CES uses a conservative hedging strategy, and expects to sell its annual generation resources of approximately 75-80 million MWHs through a combination of retail and wholesale sales, maintaining 10-20 million MWHs to mitigate risk in the event of unplanned outages or extreme weather or to take advantage of market upside opportunities through the wholesale spot market.

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Years Ended December 31, 2015	2014	2013	Increase (Decrease) 2015 vs 2014		2014 vs 2013	
REVENUES:	$ 15,026	$ 15,049	$ 14,892	$ (23)	— %	$ 157	1 %
OPERATING EXPENSES:							
Fuel	1,855	2,280	2,496	(425)	(19)%	(216)	(9)%
Purchased power	4,318	4,716	3,963	(398)	(8)%	753	19 %
Other operating expenses	3,749	3,962	3,593	(213)	(5)%	369	10 %
Pension and OPEB mark-to-market adjustment	242	835	(256)	(593)	(71)%	1,091	(426)%
Provision for depreciation	1,282	1,220	1,202	62	5 %	18	1 %
Amortization of regulatory assets, net	268	12	539	256	2,133 %	(527)	(98)%
General taxes	978	962	978	16	2 %	(16)	(2)%
Impairment of long-lived assets	42	—	795	42	— %	(795)	(100)%
Total operating expenses	12,734	13,987	13,310	(1,253)	(9)%	677	5 %
OPERATING INCOME	2,292	1,062	1,582	1,230	116 %	(520)	(33)%
OTHER INCOME (EXPENSE):							
Loss on debt redemptions	—	(8)	(132)	8	(100)%	124	(94)%
Investment income (loss)	(22)	72	33	(94)	(131)%	39	118 %
Impairment of equity method investment	(362)	—	—	(362)	— %	—	— %
Interest expense	(1,132)	(1,073)	(1,016)	(59)	5 %	(57)	6 %
Capitalized financing costs	117	118	103	(1)	(1)%	15	15 %
Total other expense	(1,399)	(891)	(1,012)	(508)	57 %	121	(12)%
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	893	171	570	722	422 %	(399)	(70)%
INCOME TAXES (BENEFITS)	315	(42)	195	357	(850)%	(237)	(122)%
INCOME FROM CONTINUING OPERATIONS	578	213	375	365	171 %	(162)	(43)%
Discontinued operations (net of income taxes of $0, $69 and $9, respectively) (Note 19)	—	86	17	(86)	(100)%	69	406 %
NET INCOME	$ 578	$ 299	$ 392	$ 279	93 %	$ (93)	(24)%
EARNINGS PER SHARE OF COMMON STOCK:							
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	169 %	$ (0.39)	(43)%
Basic - Discontinued Operations (Note 19)	—	0.20	0.04	(0.20)	(100)%	0.16	400 %
Basic - Net Income	$ 1.37	$ 0.71	$ 0.94	$ 0.66	93 %	$ (0.23)	(24)%
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	169 %	$ (0.39)	(43)%
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04	(0.20)	(100)%	0.16	400 %
Diluted - Net Income	$ 1.37	$ 0.71	$ 0.94	$ 0.66	93 %	$ (0.23)	(24)%

FirstEnergy's net income in 2015 was $578 million, or basic and diluted earnings of $1.37 per share of common stock, compared with $299 million, or basic and diluted earnings of $0.71 per share of common stock in 2014, and $392 million, or basic and diluted earnings of $0.94 per share of common stock in 2013. Highlights of the key changes in year-over-year financial results are included below:

2015 compared with 2014

As further discussed below, FirstEnergy's 2015 income from continuing operations increased $365 million as compared to 2014, resulting from a year-over-year improvement of $506 million at CES, $153 million at Regulated Distribution and $75 million at Regulated Transmission, partially offset by a $369 million decrease at Corporate/Other.

In 2015, FirstEnergy's revenues decreased $23 million as compared to 2014, primarily resulting from a $905 million decrease at CES partially offset by a $523 million increase at Regulated Distribution and a $242 million increase at Regulated Transmission.

- The decrease in revenue at CES resulted from a 31 million MWHs decline in contract sales, in line with CES' strategy discussed above, partially offset by higher wholesale sales, including increased capacity revenue associated with higher capacity auction prices.
- The increase in revenue at Regulated Distribution resulted from the implementation of new rates at certain operating companies as well as a year-over-year increase in retail generation revenue, resulting from a lower number of customers shopping with an alternative generation supplier and higher retail transmission revenue, which is recovering higher transmission related expenses. Distribution deliveries decreased 0.8%, or 1.1 million MWHs, as weather adjusted sales declined as a result of energy efficiency mandates and products and decreases in certain industrial sectors, partially offset by an increase in weather-related sales.

- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses as well as ATSI's transition to a forward-looking rate, effective January 1, 2015. These increases were partially offset by a lower ROE at ATSI in the last six months of 2015 as part of the FERC-approved settlement discussed above.

Operating expenses decreased $1,253 million in 2015 as compared to 2014, including a $593 million decrease in the Company's pension and OPEB mark-to-market adjustment, reflecting a decrease at CES of $1,747 million, partially offset by increases at Regulated Distribution and Regulated Transmission of $255 million and $73 million, respectively.

Changes in certain operating expenses include the following:

- Fuel expense declined $425 million, primarily at CES, resulting from lower fossil generation associated with low energy prices, lower unit costs, and lower settlement and termination charges on fuel and transportation contracts.
- Purchased power decreased $398 million, primarily reflecting lower volumes at CES, resulting from lower contract sales, partially offset by higher volumes at Regulated Distribution due to lower customer shopping as discussed above, and higher capacity expense associated with higher capacity rates.
- Other operating expenses decreased $213 million, primarily reflecting a decrease at CES associated with lower PJM transmission, mark-to-market and retail-related costs partially offset by higher nuclear planned outage costs, partially offset by an increase at Regulated Distribution, resulting from higher network transmission expenses, which are recovered through transmission rates as discussed above, and higher operating and maintenance expenses associated with reliability improvements.
- Amortization of regulatory assets, net increased $256 million primarily reflecting the recovery of deferred costs, including storm costs, associated with the implementation of new rates discussed above.

FirstEnergy's other expenses increased $508 million, or 57%, year-over-year, primarily resulting from a $362 million pre-tax, non-cash impairment charge associated with FEV's investment in Global Holding, lower investment income, including a $65 million increase in OTTI, and higher interest expense associated with higher average debt levels.

FirstEnergy's effective tax rate on income from continuing operations was 35.3% in 2015 compared to (24.6)% in 2014. The increase in the effective tax rate was attributable to tax planning initiatives executed during 2014, including tax benefits associated with a change in accounting method with the IRS for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain state tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

2014 compared with 2013

FirstEnergy's 2014 income from continuing operations decreased $162 million as compared to 2013 resulting from a year-over-year decline of $182 million at CES and $36 million at Regulated Distribution, partially offset by a year-over-year improvement at Regulated Transmission of $9 million and $47 million at Corporate/Other.

In 2014, FirstEnergy's revenue increased $157 million compared to 2013. The increase resulted from a $382 million increase at Regulated Distribution and a $38 million increase at Regulated Transmission, partially offset by a decrease in CES revenues of $209 million.

- The increase in revenue at Regulated Distribution resulted from higher wholesale generation sales associated with the Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of generation from AE Supply.
- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses.
- The decrease at CES resulted from lower contract sales as in 2014, CES began to reduce its exposure to weather sensitive load to more effectively hedge its generation, targeting annual contract sales of 65 to 75 million MWHs as compared to the 109 million MWHs sold in 2013. This change in strategy resulted in a 9% decrease in MWH sales in 2014 as compared to 2013.

Operating expenses increased $677 million in 2014 compared to 2013, including a $1,091 million increase in FirstEnergy's Pension and OPEB mark-to-market adjustment, primarily reflecting an increase at Regulated Distribution of $428 million, CES of $265 million and Regulated Transmission of $40 million.

Changes in certain operating expenses include the following:

- Lower fuel expense of $216 million, primarily reflected the deactivation of power plants in 2013 and increased outages. Fuel expense at CES and Regulated Distribution was further impacted by the October 2013 Harrison/Pleasants asset transfer.
- Purchased power increased $753 million, primarily reflecting higher CES purchases resulting from plant deactivations, increased outages and the asset transfer discussed above as well as higher unit pricing and capacity expense. The increase in unit pricing primarily resulted from market conditions associated with the extreme weather events in the first quarter of 2014, which included the polar vortex.
- Other operating expenses increased $369 million primarily resulting from higher costs at Regulated Distribution associated with network transmission expenses, increased vegetation management expenses in West Virginia, as well as higher operating and maintenance associated with reliability improvements, storm restoration costs and the Harrison/Pleasants

asset transfer. CES' increase in other operating expenses was primarily attributable to higher transmission costs, which resulted from the market conditions associated with the extreme weather events in the first quarter of 2014, and higher mark-to-market expenses on derivative contracts, partially offset by lower generation operating and maintenance costs primarily resulting from the deactivation of generating plants and the Harrison/Pleasants asset transfer.

FirstEnergy's other expenses decreased $121 million year-over-year, primarily resulting from the absence of a loss on debt redemptions of $124 million recognized in 2013. Higher interest expense was offset by higher investment income and capitalized financing costs, primarily attributable to Regulated Transmission's *Energizing the Future* investment plan.

FirstEnergy's effective tax rate on income from continuing operations was (24.6)% compared to 34.2% in 2013. The decrease in the effective tax rate was attributable to tax benefits recognized in 2014 associated with an IRS-approved change in accounting method for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. A reconciliation of segment financial results is provided in Note 18, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

During the fourth quarter of 2015, management concluded that FEV's 33-1/3% equity investment in Global Holding was no longer a strategic asset to CES. Because of this decision, the segment reporting was modified to reflect how management now views and makes investment decisions regarding CES and Global Holding. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2014 and 2013 have been reclassified to conform to the current presentation reflecting the activity of FEV's investment in Global Holding in Corporate/Other.

Net income by business segment was as follows:

				Increase (Decrease)	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 618	$ 465	$ 501	$ 153	$ (36)
Regulated Transmission	298	223	214	75	9
Competitive Energy Services	89	(331)	(218)	420	(113)
Corporate/Other [(1)]	(427)	(58)	(105)	(369)	47
Net Income	$ 578	$ 299	$ 392	$ 279	$ (93)
Basic Earnings Per Share:					
Continuing operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	$ (0.39)
Discontinued operations (Note 19)	—	0.20	0.04	(0.20)	0.16
Earnings per basic share	$ 1.37	$ 0.71	$ 0.94	$ 0.66	$ (0.23)
Diluted Earnings Per Share:					
Continuing operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	$ (0.39)
Discontinued operations (Note 19)	—	0.20	0.04	(0.20)	0.16
Earnings per diluted share	$ 1.37	$ 0.71	$ 0.94	$ 0.66	$ (0.23)

[(1)] Consists primarily of interest on stand-alone holding company debt, none-core business related activity and corporate income taxes.

Summary of Results of Operations — 2015 Compared with 2014

Financial results for FirstEnergy's business segments in 2015 and 2014 were as follows:

2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,429	$ 1,011	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,625	1,011	5,384	(994)	15,026
Operating Expenses:					
Fuel	533	—	1,322	—	1,855
Purchased power	3,548	—	1,456	(686)	4,318
Other operating expenses	2,242	154	1,670	(317)	3,749
Pension and OPEB mark-to-market	179	3	60	—	242
Provision for depreciation	672	156	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of long-lived assets	8	—	34	—	42
Total Operating Expenses	8,146	422	5,076	(910)	12,734
Operating Income	1,479	589	308	(84)	2,292
Other Income (Expense):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(586)	(161)	(192)	(193)	(1,132)
Capitalized financing costs	25	44	39	9	117
Total Other Expense	(519)	(117)	(169)	(594)	(1,399)
Income From Continuing Operations Before Income Taxes	960	472	139	(678)	893
Income taxes	342	174	50	(251)	315
Income From Continuing Operations	618	298	89	(427)	578
Discontinued Operations, net of tax	—	—	—	—	—
Net Income	$ 618	$ 298	$ 89	$ (427)	$ 578

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (Loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	54	(38)	72
Impairment of equity method investment	—	—	—	—	—
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized financing costs	14	55	37	12	118
Total Other Expense	(519)	(76)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(640)	(225)	171
Income taxes (benefits)	227	121	(223)	(167)	(42)
Income (Loss) From Continuing Operations	465	223	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (331)	$ (58)	$ 299

Changes Between 2015 and 2014 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 531	$ 242	$ (788)	$ 20	$ 5
Other	(8)	—	16	(36)	(28)
Internal	—	—	(133)	133	—
Total Revenues	523	242	(905)	117	(23)
Operating Expenses:					
Fuel	(34)	—	(391)	—	(425)
Purchased power	163	—	(694)	133	(398)
Other operating expenses	161	15	(405)	16	(213)
Pension and OPEB mark-to-market	(327)	1	(267)	—	(593)
Provision for depreciation	14	29	7	12	62
Amortization of regulatory assets, net	260	(4)	—	—	256
General taxes	10	32	(31)	5	16
Impairment of long-lived assets	8	—	34	—	42
Total Operating Expenses	255	73	(1,747)	166	(1,253)
Operating Income (Loss)	268	169	842	(49)	1,230
Other Income (Expense):					
Loss on debt redemptions	—	—	8	—	8
Investment income	(14)	—	(70)	(10)	(94)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	3	(30)	(3)	(29)	(59)
Capitalized financing costs	11	(11)	2	(3)	(1)
Total Other Expense	—	(41)	(63)	(404)	(508)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	268	128	779	(453)	722
Income taxes (benefits)	115	53	273	(84)	357
Income (Loss) From Continuing Operations	153	75	506	(369)	365
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income (Loss)	$ 153	$ 75	$ 420	$ (369)	$ 279

Regulated Distribution — 2015 Compared with 2014

Regulated Distribution's net income increased $153 million in 2015 compared to 2014, including a $327 million decrease in its Pension and OPEB mark-to-market adjustment. Excluding the impact of this adjustment, year-over-year earnings were impacted by increased operating expenses, including higher reliability maintenance expenses, higher benefit costs, and higher depreciation associated with increased capital investments, and a higher effective tax rate, partially offset by a net increase in new rates implemented in 2015 at certain operating companies.

Revenues —

The $523 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,993	$ 3,694	$ 299
Generation sales:			
Retail	4,303	4,043	260
Wholesale	508	661	(153)
Total generation sales	4,811	4,704	107
Transmission sales:			
Retail	513	352	161
Wholesale	112	148	(36)
Total transmission sales	625	500	125
Other	196	204	(8)
Total Revenues	$ 9,625	$ 9,102	$ 523

Distribution services revenues increased $299 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and for MP and PE in West Virginia, effective February 25, 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 1, 2015. Additionally, distribution services revenues increased resulting from the Ohio Companies' Rider DCR and higher cost recovery for above market NUG costs and certain energy efficiency programs for the Pennsylvania Companies, which was impacted by a rate increase in 2015. Partially offsetting these items were the impacts of lower residential and industrial customer usage as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	54,466	54,766	(0.5)%
Commercial	43,091	42,925	0.4 %
Industrial	50,269	51,276	(2.0)%
Other	585	586	(0.2)%
Total Electric Distribution MWH Deliveries	148,411	149,553	(0.8)%

Lower deliveries to residential customers, reflect declining weather-adjusted average customer usage due, in part, to increasing energy efficiency mandates as well as heating degree days that were 10.8% below the same period in 2014 and 2.8% below normal, partially offset by cooling degree days that were 32% above 2014 and 17% above normal. Commercial sales increased year-over-year from the increase in cooling degree days, partially offset by the lower heating degree days as well as decreased weather-adjusted usage due, in part, to increasing energy efficiency mandates. Deliveries to industrial customers decreased 2%, as the increase from shale and petroleum customer usage was more than offset by a decrease from steel and mining customer usage.

The following table summarizes the price and volume factors contributing to the $107 million increase in generation revenues in 2015 compared to 2014:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 146
Change in prices	114
	260
Wholesale:	
Effect of decrease in sales volumes	(133)
Change in prices	(75)
Capacity revenue	55
	(153)
Increase in Generation Revenues	$ 107

The increase in retail generation sales volume was primarily due to lower customer shopping in Ohio, Pennsylvania, and New Jersey and an increase in weather-related usage, partially offset by the impacts of energy efficiency as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 80% from 81% for the Ohio Companies, 65% from 67% for the Pennsylvania Companies and 50% from 52% for JCP&L. The increase in prices primarily resulted from higher default service auction results.

Wholesale generation revenues decreased $153 million in 2015 compared to 2014, primarily reflecting decreased volume associated with the termination of certain NUG contracts at JCP&L and PN and lower economic dispatch of fossil generating units associated with low spot market energy prices. Partially offsetting the decrease was an increase in capacity revenue resulting from higher capacity prices. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery, with no material impact on earnings.

The increase in retail transmission revenues of $161 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings. The decrease in wholesale transmission revenues of $36 million primarily relates to lower congestion revenue resulting from the impact of market conditions associated with the extreme weather and market conditions in 2014.

Operating Expenses —

Total operating expenses increased $255 million primarily due to the following:

- Fuel expense decreased $34 million in 2015 primarily related to lower economic dispatch resulting from low spot market energy prices.

- Purchased power costs were $163 million higher in 2015 primarily due to increased volumes reflecting lower customer shopping as described above, higher unit costs related to higher default service auction results, and higher capacity expense at MP, partially offset by lower purchases resulting from the termination of certain NUG contracts at JCP&L and PN.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 66
Change due to increased volumes	185
	251
Purchases from affiliates:	
Change due to decreased unit costs	(21)
Change due to decreased volumes	(113)
	(134)
Capacity expense	36
Amortization of deferred costs	10
Increase in Purchased Power Costs	$ 163

- Other operating expenses increased $161 million primarily due to:
    - Higher transmission expenses of $73 million primarily due to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The differences between current retail transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.
    - Increased regulated generation operating and maintenance expenses of $7 million, reflecting higher planned outage expenses in 2015 compared to 2014.
    - Higher retirement benefit costs of $22 million, reflecting higher net benefit costs before the pension and OPEB mark-to-market adjustment described below.
    - Higher distribution operating and maintenance expenses of $54 million, reflecting increased reliability maintenance in New Jersey and the Pennsylvania companies and other employee benefit costs, partially offset by lower storm restoration costs.
- Pension and OPEB mark-to-market adjustment decreased $327 million to $179 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.
- Depreciation expense increased $14 million due to a higher asset base, partially offset by lower depreciation rates at JCP&L effective with the implementation of new rates from its distribution base rate case as well as lower depreciation rates in Pennsylvania based on updated asset life studies approved by the PPUC.
- Net regulatory asset amortization increased $260 million primarily due to:
    - Recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above ($66 million),
    - Higher energy efficiency program cost recovery ($66 million),
    - Lower deferral of TTS costs in West Virginia ($37 million),
    - Higher amortizations of above-market NUG costs in Pennsylvania and New Jersey ($36 million),
    - Lower deferral of West Virginia vegetation management expenses ($31 million),
    - Higher default generation service cost amortization ($28 million), and
    - Recovery of Pennsylvania legacy meter costs ($22 million); partially offset by
    - Higher cost deferral of Ohio network transmission expenses ($33 million).
- General taxes increased $10 million primarily due to higher revenue-related taxes in Pennsylvania, partially offset by lower property taxes in Ohio.

Other Expense —

Other expense was flat in 2015 as compared to 2014, as lower investment income was offset by lower interest expense and higher capitalized financing costs.

Income Taxes —

Regulated Distribution's effective tax rate was 35.6% and 32.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Regulated Transmission — 2015 Compared with 2014

Net income increased $75 million in 2015 compared to 2014. Higher Transmission revenues associated with ATSI's "forward looking" rate and higher rate base were partially offset by higher interest expense and lower capitalized financing costs.

Revenues —

Total revenues increased $242 million principally at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base. Effective January 1, 2015, ATSI's formula rate calculation transitioned to a "forward looking" approach, where transmission revenues are based on actual costs.

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

	For the Years Ended December 31,		
Revenues by Transmission Asset Owner	**2015**	**2014**	**Increase**
		(In millions)	
ATSI	$ 446	$ 242	$ 204
TrAIL	252	214	38
PATH	13	13	—
Utilities	300	300	—
Total Revenues	$ 1,011	$ 769	$ 242

Operating Expenses —

Total operating expenses increased $73 million principally due to higher operating and maintenance expenses, depreciation, and property taxes at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expenses —

Other expenses increased $41 million due to increased interest expense resulting from debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings as well as lower capitalized financing costs.

Income Taxes —

Regulated Transmission's effective tax rate was 36.9% and 35.2% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

CES — 2015 Compared with 2014

Operating results increased $420 million in 2015 compared to 2014, primarily from higher capacity revenues and the absence of the impact of the high market prices associated with extreme weather events and unplanned outages in 2014 that resulted in higher purchased power and transmission costs, partially offset by lower contract sales volumes. Additionally, changes in year-over-year operating results were impacted by lower Pension and OPEB mark-to-market adjustments, lower settlement and termination costs related to coal and transportation contracts, and the absence of a $78 million after-tax gain on the sale of certain hydroelectric facilities recognized in February 2014.

Revenues —

Total revenues decreased $905 million in 2015, compared to 2014, primarily due to decreased sales volumes in line with CES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices compared to 2014 as a result of increased channel pricing as well as higher capacity revenues, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
		(In millions)	
Contract Sales:			
Direct	$ 1,269	$ 2,359	$ (1,090)
Governmental Aggregation	1,012	1,184	(172)
Mass Market	265	452	(187)
POLR	712	902	(190)
Structured Sales	558	522	36
Total Contract Sales	3,816	5,419	(1,603)
Wholesale	1,225	461	764
Transmission	138	220	(82)
Other	205	189	16
Total Revenues	$ 5,384	$ 6,289	$ (905)

MWH Sales by Channel	For the Years Ended December 31, 2015	2014	Increase (Decrease)
		(In thousands)	
Contract Sales:			
Direct	23,585	44,012	(46.4)%
Governmental Aggregation	15,443	19,569	(21.1)%
Mass Market	3,878	6,773	(42.7)%
POLR	11,950	15,708	(23.9)%
Structured Sales	12,902	12,814	0.7 %
Total Contract Sales	67,758	98,876	(31.5)%
Wholesale	7,326	680	977.4 %
Total MWH Sales	75,084	99,556	(24.6)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (1,095)	$ 5	$ —	$ —	$ (1,090)
Governmental Aggregation	(249)	77	—	—	(172)
Mass Market	(193)	6	—	—	(187)
POLR	(216)	26	—	—	(190)
Structured Sales	3	33	—	—	36
Wholesale	197	(8)	107	468	764

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflect CES' efforts to more effectively hedge its generation by reducing exposure to weather-sensitive load. Although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price, partially offset by a lower energy component of the retail price resulting

from lower year-over-year market prices. The Direct, Governmental Aggregation and Mass Market customer base was 1.6 million as of December 31, 2015, compared to 2.1 million as of December 31, 2014.

The decrease in POLR sales of $190 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $36 million due to low market prices that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $764 million primarily due to an increase in capacity revenue from higher capacity prices, increase in short-term (net hourly position) transactions, and higher net gains on financially settled contracts, partially offset by lower spot market energy prices which limited additional wholesale sales.

Transmission revenue decreased $82 million primarily due to lower congestion revenue resulting from the market conditions associated with the extreme weather events in 2014.

Other revenue increased $16 million primarily due to higher lease revenues from additional equity interests in affiliated sale and leasebacks repurchased in November 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $1,747 million in 2015 due to the following:

- Fuel costs decreased $391 million primarily due to lower economic dispatch of fossil units resulting from low spot market energy prices and lower nuclear unit prices, resulting from the suspension of the DOE nuclear disposal fee, effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. The impact of terminations and settlements of coal and transportation contracts resulted in a pre-tax loss of $67 million and $166 million in 2015 and 2014, respectively.

- Purchased power costs decreased $694 million due to lower volumes ($888 million), partially offset by higher unit prices ($39 million) and higher capacity expenses ($155 million). Lower volumes were primarily due to decreased load requirements resulting from lower sales as discussed above, partially offset by lower fossil generation as discussed above. The higher unit prices are primarily due to higher losses on financially settled contracts, partially offset by lower market prices in 2015 as compared to 2014. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.

- Nuclear operating costs increased $84 million as a result of higher planned outage costs and higher employee benefit expenses. There were three planned refueling outages in 2015 as compared to two planned outages in 2014.

- Transmission expenses decreased $273 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in 2014.

- General taxes decreased $31 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

- Pension and OPEB mark-to-market adjustment decreased $267 million to $60 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

- Other operating expenses decreased $212 million primarily due to a $141 million decrease in mark-to-market expenses on commodity contract positions reflecting lower market prices and a $71 million decrease in retail-related costs.

- Impairments of long-lived assets increased $34 million due to impairment charges associated with non-core assets.

Other Expense —

Total other expense increased $63 million in 2015 compared to 2014 primarily due to higher OTTI on NDT investments, partially offset by the absence of an $8 million loss on debt redemptions incurred in 2014.

Discontinued Operations —

There were no discontinued operations in 2015. In 2014, discontinued operations primarily included a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of certain hydroelectric assets on February 12, 2014.

Income Taxes (Benefits) —

CES' effective tax rate was 36.0% and 34.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Corporate/Other — 2015 Compared with 2014

Financial results from Corporate/Other resulted in a $369 million decrease in net income in 2015 compared to 2014 primarily due to a $362 million pre-tax impairment of FirstEnergy's equity method investment in Global Holding, higher costs associated with environmental remediation at legacy plants, higher interest expense and a higher effective tax rate. During 2015, based on the significant decline in coal pricing and the current outlook for the coal market, FirstEnergy assessed the carrying value of its investment in Global Holding and determined there was an other than temporary decline in the fair value below its carrying value, which resulted in the impairment charge. The increased interest expense primarily relates to a $1 billion term loan entered into in March 2014 and a gain on the termination of interest rate swap arrangements recognized in 2014. The higher effective tax rate primarily resulted from the absence of tax benefits recognized in 2014 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, a reduction in state deferred tax liabilities resulting from changes in state apportionment factors, the elimination of certain tax liabilities associated with basis differences as well as certain tax benefits recorded in 2014 that related to prior periods.

Summary of Results of Operations — 2014 Compared with 2013

Financial results for FirstEnergy's business segments in 2014 and 2013 were as follows:

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	54	(38)	72
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized interest	14	55	37	12	118
Total Other Expense	(519)	(76)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(640)	(225)	171
Income taxes (benefits)	227	121	(223)	(167)	(42)
Income (Loss) From Continuing Operations	465	223	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (331)	$ (58)	$ 299

2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,499	$ 731	$ 5,542	$ (161)	$ 14,611
Other	221	—	186	(126)	281
Internal	—	—	770	(770)	—
Total Revenues	8,720	731	6,498	(1,057)	14,892
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)	1,257	422	(60)	(37)	1,582
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	57	—	14	(38)	33
Interest expense	(543)	(93)	(222)	(158)	(1,016)
Capitalized interest	31	14	42	16	103
Total Other Expense	(455)	(79)	(315)	(163)	(1,012)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	802	343	(375)	(200)	570
Income taxes (benefits)	301	129	(140)	(95)	195
Income From Continuing Operations	501	214	(235)	(105)	375
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	$ 501	$ 214	$ (218)	$ (105)	$ 392

Changes Between 2014 and 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 399	$ 38	$ (261)	$ (32)	$ 144
Other	(17)	—	3	27	13
Internal	—	—	49	(49)	—
Total Revenues	382	38	(209)	(54)	157
Operating Expenses:					
Fuel	190	—	(406)	—	(216)
Purchased power	77	—	725	(49)	753
Other operating expenses	308	8	68	(15)	369
Pension and OPEB mark-to-market	655	2	434	—	1,091
Provision for depreciation	52	13	(52)	5	18
Amortization of regulatory assets, net	(528)	1	—	—	(527)
General taxes	(4)	16	(31)	3	(16)
Impairment of long-lived assets	(322)	—	(473)	—	(795)
Total Operating Expenses	428	40	265	(56)	677
Operating Income (Loss)	(46)	(2)	(474)	2	(520)
Other Income (Expense):					
Loss on debt redemptions	—	—	141	(17)	124
Investment income	(1)	—	40	—	39
Interest expense	(46)	(38)	33	(6)	(57)
Capitalized interest	(17)	41	(5)	(4)	15
Total Other Expense	(64)	3	209	(27)	121
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	(110)	1	(265)	(25)	(399)
Income taxes (benefits)	(74)	(8)	(83)	(72)	(237)
Income (Loss) From Continuing Operations	(36)	9	(182)	47	(162)
Discontinued Operations, net of tax	—	—	69	—	69
Net Income (Loss)	$ (36)	$ 9	$ (113)	$ 47	$ (93)

Regulated Distribution — 2014 Compared with 2013

Regulated Distribution's net income decreased $36 million in 2014 compared to 2013. Regulated Distribution's Pension and OPEB mark-to-market adjustment increased $655 million which was partially offset by a reduction in regulatory asset impairment charges of $305 million and an impairment of long-lived assets of $322 million incurred in 2013. Excluding the impact of these charges, year-over-year earnings were impacted by higher distribution operating and maintenance costs, including the impact of higher benefit costs, higher depreciation and property taxes, and higher interest expense from debt issuances. These items were partially offset by slightly higher distribution deliveries, higher earnings associated with the October 2013 Harrison/Pleasants asset transfer, and a lower effective tax rate.

Revenues —

The $382 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,694	$ 3,762	$ (68)
Generation sales:			
Retail	4,043	3,959	84
Wholesale	661	330	331
Total generation sales	4,704	4,289	415
Transmission sales:			
Retail	352	347	5
Wholesale	148	101	47
Total transmission sales	500	448	52
Other	204	221	(17)
Total Revenues	$ 9,102	$ 8,720	$ 382

The decrease in distribution services revenue is primarily related to a decrease in revenues from ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013 and a rider rate decrease associated with the recovery of energy efficiency and other customer program costs for the Pennsylvania Companies. This was partially offset by higher electric distribution MWH deliveries of 1.1% as described below, rate increases for the Ohio Companies associated with energy efficiency performance shared savings and the Rider DCR, and higher revenues for the Pennsylvania Companies associated with the recovery of Smart Meter program costs. Certain Ohio energy efficiency programs permit the Ohio Companies to bill and collect shared savings revenues if energy efficiency programs meet or exceed the state mandates. Additionally, the Rider DCR provides for recovery of incremental operating expenses and a return on rate base associated with incremental distribution plant investments in Ohio. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2014	2013	Increase
		(In thousands)	
Residential	54,766	54,479	0.5%
Commercial	42,925	42,582	0.8%
Industrial	51,276	50,243	2.1%
Other	586	584	0.3%
Total Electric Distribution MWH Deliveries	149,553	147,888	1.1%

Higher deliveries to residential customers primarily reflect increased weather-related usage resulting from heating degree days that were 7% above 2013, and 9% above normal, partially offset by cooling degree days that were 15% below 2013, and 12% below normal. Increased deliveries to commercial customers reflect improving economic conditions across FirstEnergy's service territories. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical and paper customers.

The following table summarizes the price and volume factors contributing to the $415 million increase in generation revenues in 2014 compared to 2013:

Source of Change in Generation Revenues	Increase
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 14
Change in prices	70
	84
Wholesale:	
Effect of increase in sales volumes	166
Change in prices	79
Capacity revenue	86
	331
Increase in Generation Revenues	$ 415

The increase in retail generation sales volume was primarily due to weather-related usage, as described above, and improving economic conditions, partially offset by increased customer shopping in Pennsylvania. The increase in retail generation prices reflects higher Pennsylvania PTC prices, 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 effective June 2013. Additionally, the impact on retail generation prices of MP's Temporary Transaction Surcharge (TTS) associated with the October 2013 Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs. As part of the TTS, MP earns a return on and of the Harrison plant costs.

The increase in wholesale generation revenues of $331 million in 2014 resulted from increased volume and energy prices associated with market conditions related to extreme weather events in January 2014 and increased capacity revenue related to the October 2013 Harrison/Pleasants asset transfer whereby MP acquired from AE Supply 1,476 MWs of net capacity. During January 2014, unprecedented customer demand associated with prolonged periods of bitterly cold temperatures and unit unavailability across the PJM footprint resulted in severe market price volatility for electricity and natural gas throughout PJM. Eight of the ten highest winter demands for electricity on the PJM system occurred in January 2014. The difference between wholesale generation revenues, primarily associated with MP's regulated generation, and certain energy costs are deferred for future recovery, with no material impact to earnings.

The increase in transmission revenues of $52 million reflects higher PJM revenues at MP associated with market conditions related to extreme weather events described above and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013 as discussed above. Network transmission costs are now recovered through WP's generation rate.

Other revenues decreased $17 million primarily due to less customer requested work in 2014 compared to 2013.

Operating Expenses —

Total operating expenses increased by $428 million primarily due to the following:

- Fuel expense was $190 million higher in 2014 primarily related to increased generation as a result of the October 2013 Harrison/Pleasants asset transfer.

- Purchased power costs were $77 million higher in 2014 primarily due to increased unit prices and capacity expense reflecting higher auction clearing prices, partially offset by a decrease in purchased volumes required.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 127
Change due to decreased volumes	(134)
	(7)
Purchases from affiliates:	
Change due to increased unit costs	39
Change due to increased volumes	2
	41
Capacity expense	58
Increase in costs deferred	(15)
Increase in Purchased Power Costs	$ 77

Other operating expenses increased $308 million primarily due to:

- Higher transmission expenses of $130 million primarily due to PJM transmission costs associated with higher congestion rates at MP as a result of market conditions related to extreme weather events in January 2014 and higher PJM transmission costs resulting from the October 2013 Harrison/Pleasants asset transfer. The differences between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.

- Higher distribution operating and maintenance expenses of $75 million resulting from higher maintenance activities and storm related restoration expenses, including $26 million of storm expenses deferred for future recovery.

- Higher vegetation management expenses in West Virginia of $33 million, which were deferred for future recovery per authorization of the WVPSC.

- Higher retirement benefit costs of $33 million primarily reflecting higher net periodic benefit costs before the pension and OPEB mark-to-market adjustments discussed below.

- Increased regulated generation operating and maintenance expenses of $23 million, reflecting increased costs associated with the October 2013 Harrison/Pleasants asset transfer and a planned outage at Fort Martin.

- Pension and OPEB mark-to-market adjustments increased $655 million to $506 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.

- Depreciation expense increased $52 million due to a higher asset base, including $22 million at MP associated with the October 2013 Harrison/Pleasants asset transfer.

- Net regulatory asset amortization decreased $528 million primarily due to:
  - Impairment charges on regulatory assets of $305 million associated with the recovery of marginal transmission losses at ME and PN ($254 million) and the recovery of RECs for the Ohio Companies ($51 million) that occurred in 2013,
  - Decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies ($67 million),
  - Lower default generation service and NUG costs recovery in Pennsylvania ($48 million),
  - Increased deferral of West Virginia vegetation management expenses ($33 million) and customer refunds associated with the gain on the Pleasants plant resulting from the October 2013 Harrison/Pleasants asset transfer ($36 million), and
  - Higher storm cost deferrals ($26 million).

- General taxes decreased $4 million primarily due to lower revenue-related taxes, partially offset by higher property taxes and an increase in the West Virginia business and occupation tax as a result of the October 2013 Harrison/Pleasants asset transfer.

- The 2013 impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of the Harrison plant to the amount permitted to be included in rate base as part of the October 2013 Harrison/Pleasants asset transfer.

Other Expense —

Other expense increased $64 million in 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million associated with the financing of the October 2013 Harrison/Pleasants asset transfer, a new debt issuance of $500 million in August 2013 at JCP&L and lower capitalized financing costs related primarily to a decrease in the rate used for borrowed funds.

Income Taxes —

Regulated Distribution's effective tax rate was 32.8% and 37.5% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors, an increase in state flow through income tax benefits and other realized tax benefits.

Regulated Transmission — 2014 Compared with 2013

Net income increased $9 million in 2014 compared to 2013. Higher Transmission revenues associated with increased capital investments and higher capitalized financing costs were partially offset by higher operating expenses and interest expense.

Revenues —

Total revenues increased $38 million principally due to higher revenue at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base as included in their annual rate filings effective June 2013 and June 2014.

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

	For the Years Ended December 31,		
Revenues by Transmission Asset Owner	**2014**	**2013**	**Increase (Decrease)**
		(In millions)	
ATSI	$ 242	$ 209	$ 33
TrAIL	214	207	7
PATH	13	20	(7)
Utilities	300	295	5
Total Revenues	$ 769	$ 731	$ 38

Operating Expenses —

Total operating expenses increased $40 million principally due to higher property taxes, depreciation and other operating expenses.

Other Expenses —

Total other expenses decreased $3 million principally due to higher capitalized financing costs of $41 million related to increased construction work in progress balances associated with the *Energizing the Future* investment plan, partially offset by increased interest expense resulting from new debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings.

Income Taxes —

Regulated Transmission's effective tax rate was 35.2% and 37.6% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from an increase in AFUDC equity flow through.

CES — 2014 Compared with 2013

Operating results decreased $113 million in 2014, compared to 2013. Lower impairment charges of $473 million associated with the deactivation of the Hatfield and Mitchell generating units and a lower loss on debt redemptions of $141 million were partially offset with higher Pension and OPEB mark-to-market adjustments of $434 million. Excluding the impact of these charges, year-over-year earnings were impacted by lower sales volumes, reflecting CES' selling efforts discussed below and an increase in purchased power and transmission costs incurred to serve contract sales due to market conditions associated with the extreme weather events in January 2014. Partially offsetting these items were lower operating expenses due to lower retail-related costs, lower generation costs resulting from plant deactivations and asset transfers, and higher capacity revenues from higher auction prices. Additionally, operating results were impacted by a $78 million after-tax gain on the sale of certain hydro facilities in February 2014.

Revenues —

Total revenues decreased $209 million in 2014, compared to 2013, primarily due to decreased sales volumes in the Direct and Governmental Aggregation sales channels, partially offset by higher volume in the Structured Sales channel. Revenues were also impacted by higher unit prices as a result of increased channel pricing and higher capacity revenues, as described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Contract Sales:			
Direct	$ 2,359	$ 2,913	$ (554)
Governmental Aggregation	1,184	1,185	(1)
Mass Market	452	448	4
POLR	902	858	44
Structured Sales	522	421	101
Total Contract Sales	5,419	5,825	(406)
Wholesale	461	343	118
Transmission	220	144	76
Other	189	186	3
Total Revenues	$ 6,289	$ 6,498	$ (209)

MWH Sales by Channel	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In thousands)	
Contract Sales:			
Direct	44,012	56,145	(21.6)%
Governmental Aggregation	19,569	20,859	(6.2)%
Mass Market	6,773	6,761	0.2 %
POLR	15,708	15,758	(0.3)%
Structured Sales	12,814	9,047	41.6 %
Total Contract Sales	98,876	108,570	(8.9)%
Wholesale	680	1,250	(45.6)%
Total MWH Sales	99,556	109,820	(9.3)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (629)	$ 75	$ —	$ —	$ (554)
Governmental Aggregation	(73)	72	—	—	(1)
Mass Market	1	3	—	—	4
POLR	(3)	47	—	—	44
Structured Sales	176	(75)	—	—	101
Wholesale	(17)	—	(21)	156	118

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflects CES' efforts to more effectively hedge its generation by reducing exposure to weather sensitive load. Additionally, although unit pricing was higher year-over-year in the Direct, Governmental Aggregation and Mass Market channels noted above, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase in prices associated with capacity was partially offset by lower energy pricing built into the retail product at the time customers were acquired for 2014 sales. Beginning in the fourth quarter of 2011, when there was a significant decline in energy prices, CES' 2014 retail sales position was approximately 30% committed, whereas its 2013 retail sales position was approximately 60% committed, resulting in a greater proportion of 2014 sales and unit prices being impacted by the decline in the energy prices.

The increase in POLR revenues of $44 million was due to higher rates associated with the capacity expense component of the rate discussed above, partially offset by lower sales volumes. The increase in Structured Sales revenues of $101 million was due to higher sales volumes, partially offset by lower unit prices primarily due to market conditions related to extreme weather events in 2014 that reduced the gains on various structured financial sales contracts.

Wholesale revenues increased $118 million primarily due to an increase in capacity revenue from higher capacity prices, partially offset by a decrease in short-term (net hourly positions) transactions. The decrease in Wholesale sales volumes was due to lower generation available to sell primarily as a result of the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013.

Transmission revenue increased $76 million due to higher congestion revenue driven by market conditions related to extreme weather events in 2014, as discussed above.

Other revenue increased $3 million in 2014 as compared to 2013 as higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since 2013, partially offset by a $17 million pre-tax gain recognized in 2013 on the sale of property to a regulated affiliate. CES earns lease revenue associated with the equity interests it has purchased.

Operating Expenses —

Total operating expenses increased $265 million in 2014 due to the following:

- Fuel costs decreased $406 million primarily due to lower generation volumes resulting from the October 2013 Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013 and increased outages as compared to the same period of 2013. Higher unit prices, primarily driven by increased peaking generation, was partially offset by the suspension of the DOE nuclear disposal fee, which was effective May 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. Terminations and settlements associated with damages on coal and transportation contracts were approximately $166 million and $128 million in 2014 and 2013, respectively.

- Purchased power costs increased $725 million due to higher volumes ($252 million), increased unit prices ($565 million) and higher capacity expenses ($311 million), partially offset by lower losses on financially settled contracts ($403 million). Higher purchased volumes were primarily due to lower available generation due to outages, the October 2013 Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013, partially offset by lower contract sales as described above. The increase in unit prices was primarily a result of market conditions related to extreme weather events in January 2014, partially offset by lower losses on financially settled contracts. The increase in capacity expense, which is a component of the segment's retail price, was primarily the result of higher capacity rates associated with the segment's retail sales obligations.

- Fossil operating costs decreased $73 million primarily due to lower contractor, labor and materials and equipment costs resulting from previously deactivated units and the October 2013 Harrison/Pleasants asset transfer.
- Nuclear operating costs increased $6 million as a result of higher labor, contractor, materials and equipment costs. There were two refueling outages in each of 2014 and 2013, however, the duration of the outages in 2014 exceeded the prior year.
- Transmission expenses increased $80 million primarily due to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in 2014. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.
- General taxes decreased $31 million primarily due to lower gross receipts taxes resulting from reduced retail sales volumes, lower payroll taxes as a result of lower labor costs noted above, lower property taxes due to the October 2013 Harrison/Pleasants asset transfer, and reduced Ohio personal property taxes.
- Impairments of long-lived assets decreased $473 million due to the impairment of two unregulated, coal-fired generating plants recognized in 2013.
- Depreciation expense decreased $52 million primarily due to a reduction in the asset base as a result of the plant deactivations and the October 2013 Harrison/Pleasants asset transfer noted above.
- Pension and OPEB mark-to-market adjustments increased $434 million to $327 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.
- Other operating expenses increased $55 million primarily due to an increase in mark-to-market expenses on commodity contract positions, and an impairment of deferred advertising costs of $23 million associated with the elimination of future selling efforts in the Mass Market and certain Direct sales channels, partially offset by lower retail and marketing related costs.

Other Expense —

Total other expense in 2014 decreased $209 million compared to 2013 due to the absence of a $141 million loss on debt redemptions in connection with senior notes that were repurchased in 2013, higher investment income primarily on the NDT investments, lower OTTI and lower net interest expense of $28 million due to debt redemptions.

Income Tax Benefits —

CES' effective tax rate was 34.8% and 37.3% for 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pre-tax losses, primarily resulted from changes in state apportionment factors and higher valuation allowances on certain NOL carryforwards.

Discontinued Operations —

Discontinued operations increased $69 million in 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of hydro assets in February 2014.

Corporate/Other — 2014 Compared with 2013

Financial results from Corporate/Other resulted in a $47 million increase in net income in 2014 compared to 2013 primarily due to higher tax benefits, partially offset by $17 million of gains on debt redemptions in 2013. The higher tax benefits primarily resulted from an IRS-approved change in accounting method that increased the tax basis of certain assets resulting in higher future tax deductions, and the resolution of state tax benefits resulting from the expiration of the statute of limitation on certain state tax positions. Additional income tax benefits of $25 million were recognized in 2014 that relate to prior periods. The out-of-period adjustment primarily related to the correction of amounts included on FirstEnergy's tax basis balance sheet. Management has determined that these adjustments are not material to the current or any prior period. The 2013 effective tax rate benefited from reductions to valuation allowances against state NOL carryforwards, as well as changes in state apportionment factors, which reduced deferred tax liabilities.

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, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets (Liabilities) by Source	December 31, 2015	December 31, 2014	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 185	$ 240	$ (55)
Customer receivables for future income taxes	355	370	(15)
Nuclear decommissioning and spent fuel disposal costs	(272)	(305)	33
Asset removal costs	(372)	(254)	(118)
Deferred transmission costs	115	90	25
Deferred generation costs	243	281	(38)
Deferred distribution costs	335	182	153
Contract valuations	186	153	33
Storm-related costs	403	465	(62)
Other	170	189	(19)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,348	$ 1,411	$ (63)

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of December 31, 2015 and 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

As of December 31, 2015 and December 31, 2014, FirstEnergy had approximately $116 million and $243 million 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 payments, dividend payments, and contributions to its pension plan. During 2015, FirstEnergy received $630 million of cash dividends and capital returned from its subsidiaries and paid $607 million in cash dividends to common shareholders. In addition to internal sources to fund liquidity and capital requirements for 2016 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. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, subject to market and other conditions.

Additionally in 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions.

FirstEnergy's longer term strategic outlook for its regulated and competitive businesses will be determined following resolution of the Ohio Companies' ESP IV, including the proposed PPA between FES and the Ohio Companies. Once the ESP IV is finalized, FirstEnergy expects to be in a position to more fully understand the longer-term outlook of its competitive businesses and the longer term growth rate of its regulated businesses, including planned capital investments and any additional equity to fund growth in its regulated businesses. With the exception of Regulated Transmission's 2016 projected capital expenditures discussed below, planned capital expenditures for 2016 for Regulated Distribution, CES, and Corporate/Other will depend on the outcome of the Ohio Companies' ESP IV and remain subject to Board approval.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion *Energizing the Future* investment plan that began in 2014 and will continue through 2017 to upgrade and expand FirstEnergy's transmission system. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. In total, FirstEnergy has identified at least $15 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017.

In alignment with FirstEnergy's strategy to invest in its Regulated Transmission and Regulated Distribution segments and the repositioning of the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at each business unit, and maintaining strong liquidity for an overall stable financial position. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

As part of an ongoing effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three-year period.

Any financing plans by FirstEnergy, including the issuance of equity, refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such issuances, financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

As of December 31, 2015, 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, 2015, included the following:

Currently Payable Long-Term Debt	***(In millions)***
PCRBs supported by bank LOCs [(1)]	$ 92
FMBs	245
Unsecured notes	300
Unsecured PCRBs [(1)]	391
Collateralized lease obligation bonds	23
Sinking fund requirements	87
Other notes	28
	$ 1,166

(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 / Revolving Credit Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was as follows:

Borrower(s)	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy[(1)]	Revolving	March 2019	$ 3,500	$ 1,595
FES / AE Supply	Revolving	March 2019	1,500	1,442
FET[(2)]	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 4,037
		Cash	—	63
		Total	$ 6,000	$ 4,100

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

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) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

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, 2015:

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	$ 3,500	$ —	$ —	$ — [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	—	—	500 [3]
ME	300	—	—	500 [3]
PN	300	—	—	300 [3]
WP	200	—	—	200 [3]
MP	500	—	—	500 [3]
PE	150	—	—	150 [3]
ATSI	—	—	500	500 [3]
Penn	50	—	—	100 [3]
TrAIL	—	—	400	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, $600 million of the FE 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.

As of December 31, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants under the respective Facilities.

Term Loans

FE has a $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan with a maturity date of May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2015, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants under each of these term loans.

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 2015 was 0.84% per annum for the regulated companies' money pool and 1.64% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2015, FirstEnergy's currently payable long-term debt included approximately $92 million of FES 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, 2015 were issued by the following bank:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	$ 92	March 2017	March 2017

[1] Excludes approximately $1 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, 2015:

	Senior Secured		Senior Unsecured		
Issuer	S&P	Moody's	S&P	Moody's	Fitch
FE	—	—	BB+	Baa3	BB+
FES	BBB-	—	BBB-	Baa3	—
AE Supply	BBB-	—	BBB-	Baa3	—
AGC	—	—	BBB-	Baa3	—
ATSI	—	—	BBB-	Baa2	—
CEI	BBB+	Baa1	BBB-	Baa3	—
FET	—	—	BB+	Baa3	
JCP&L	—	—	BBB-	Baa2	—
ME	—	—	BBB-	Baa1	—
MP	BBB+	A3	—	—	—
OE	BBB+	A2	BBB-	Baa1	—
PN	—	—	BBB-	Baa2	—
Penn	—	A2	—	—	—
PE	BBB+	A3	—	—	—
TE	BBB	Baa1	—	—	—
TrAIL	—	—	BBB-	A3	—
WP	BBB+	A2	—	—	—

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of December 31, 2015, FE and its subsidiaries could issue additional debt of approximately $5.1 billion and remain within the limitations of the financial covenants required by the Facilities. As of December 31, 2015, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $5.1 billion given FE's consolidated debt to total capitalization ratio under the FE Facility.

Changes in Cash Position

As of December 31, 2015, FirstEnergy had $131 million of cash and cash equivalents compared to $85 million of cash and cash equivalents as of December 31, 2014. As of December 31, 2015 and 2014, FirstEnergy had approximately $82 million and $79 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's most significant sources of cash are derived from electric services provided by its utility operating subsidiaries and the sale of energy and related products and services by its unregulated competitive subsidiaries. The most significant use of cash from operating activities is to buy electricity in the wholesale market and pay fuel suppliers, interest, employees, tax authorities, lenders and others for a wide range of materials and services.

Net cash provided from operating activities was $3,447 million during 2015, $2,713 million during 2014 and $2,662 million during 2013. Cash flows from operations increased $734 million in 2015 compared with 2014 due to the following:

- Distribution rate increases associated with the implementation of new rates, partially offset by a year-over-year decline in distribution deliveries;
- Higher transmission revenue and earnings, reflecting recovery of incremental operating expenses, a higher rate base and forward-looking rates at ATSI;
- Higher capacity revenues at CES, partially offset by a decline in sales volume;
- Lower disbursements for fuel and purchased power resulting from the lower sales volumes; and
- Lower posted collateral; partially offset by,
- A $143 million contribution to the qualified pension plan in 2015.

Cash Flows From Financing Activities

In 2015, cash used for financing activities was $279 million compared to $513 million and $477 million of net cash provided from financing activities during 2014 and 2013, respectively. The following table summarizes new debt financing (net of any discounts), redemptions and common stock dividend payments:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Repaid	**2015**	**2014**	**2013**
		(In millions)	
New Issues			
Unsecured notes	$ 475	$ 2,400	$ 2,300
PCRBs	339	878	—
FMBs	295	200	1,000
Term loan	200	1,050	—
Senior secured notes	2	—	445
	$ 1,311	$ 4,528	$ 3,745
Redemptions / Repayments			
Unsecured notes	$ —	$ (600)	$ (2,284)
PCRBs	(313)	(793)	(470)
FMBs	(215)	(175)	(420)
Term loan	(200)	—	—
Senior secured notes	(151)	(191)	(376)
Long-term revolving credit	—	—	(50)
	$ (879)	$ (1,759)	$ (3,600)
Tender premiums paid on debt redemptions	$ —	$ —	$ (110)
Short-term borrowings, net	$ (91)	$ (1,605)	$ 1,435
Common stock dividend payments	$ (607)	$ (604)	$ (920)

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

In August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L's short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also, in the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

In October 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, in October 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

Cash Flows From Investing Activities

Cash used for investing activities in 2015 principally represented cash used for property additions. The following table summarizes investing activities for 2015, 2014 and 2013:

	For the Years Ended December 31,		
Cash Used for Investing Activities	**2015**	**2014**	**2013**
		(In millions)	
Property Additions:			
Regulated distribution	$ 1,108	$ 972	$ 1,272
Regulated transmission	952	1,329	461
Competitive energy services	588	939	827
Other and reconciling adjustments	56	72	78
Nuclear fuel	190	233	250
Proceeds from asset sales	(20)	(394)	(4)
Investments	107	68	72
Asset removal costs	142	153	146
Other	(1)	(13)	(9)
	$ 3,122	$ 3,359	$ 3,093

Cash used for investing activity in 2015 as compared to 2014 were impacted by lower property additions of $608 million, partially offset by a $374 million reduction in proceeds received from asset sales, as 2014 included proceeds from the sale of certain hydroelectric assets. The decline in property additions were due to the following:

- a decrease of $351 million at CES, resulting from the absence of capital investments associated with the Davis-Besse steam generators that were placed into service in May 2014,
- a decrease of $377 million at Regulated Transmission primarily relating to the timing of capital investments associated with its *Energizing the Future* investment program, partially offset by
- an increase of $136 million at Regulated Distribution relating to utility specific project investments and costs associated with the Pennsylvania smart meter program.

CONTRACTUAL OBLIGATIONS

As of December 31, 2015, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2016	2017-2018	2019-2020	Thereafter
			(In millions)		
Long-term debt[1]	$ 20,238	$ 1,039	$ 3,435	$ 3,499	$ 12,265
Short-term borrowings	1,708	1,708	—	—	—
Interest on long-term debt[2]	12,523	1,015	1,839	1,500	8,169
Operating leases[3]	2,083	184	254	207	1,438
Capital leases[3]	150	36	55	32	27
Fuel and purchased power[4]	13,578	1,812	2,539	2,117	7,110
Capital expenditures [5]	2,213	877	938	398	—
Pension funding	3,564	381	1,122	787	1,274
Total	$ 56,057	$ 7,052	$ 10,182	$ 8,540	$ 30,283

(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, 2015.
(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) Amounts represent committed capital expenditures as of December 31, 2015.

Excluded from the table 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 $3.5 billion in 2016, $0.5 billion of which are expected to relate to the Utilities' contracts with FES.

The table above also excludes regulatory liabilities (see Note 14, Regulatory Matters), AROs (see Note 13, Asset Retirement Obligations), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 15, Commitments, Guarantees and Contingencies) since the amount and timing of the cash payments are uncertain. The table also excludes accumulated deferred income taxes and investment tax credits since cash payments for income taxes are determined based primarily on taxable income for each applicable fiscal year.

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 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 (NG-$501 million) per incident but not more than $76 million (NG-$75 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 annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) 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 $15 million (NG-$15.1 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 $83 million (NG-$81 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. The maximum potential amount of future payments FirstEnergy could be required to make under these guarantees as of December 31, 2015, was approximately $3.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 33
Deferred compensation arrangements	533
Other[2]	17
	583
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts[3]	251
FES' guarantee of NG's nuclear property insurance	98
FES' guarantee of nuclear decommissioning costs	21
FES' guarantee of FG's sale and leaseback obligations	1,767
	2,137
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	398
Surety Bonds	22
FES' LOC (long-term tax-exempt debt)[4]	93
LOCs[5]	154
	667
Total Guarantees and Other Assurances	$ 3,687

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

(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $7 million for railcar leases, and $6 million for various leases.

(3) Includes energy and energy-related contracts associated with FES of approximately $248 million.

(4) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities and the principal amount of floating-rate PCRBs of $92 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(5) Includes $54 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $88 million issued in connection with energy and energy related contracts, $2 million issued in connection with railcar leases, $7 million pledged in connection with the sale and leaseback of the Beaver Valley Unit 2 by OE and $3 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, 2015, FES has posted collateral of $188 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 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, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 198	$ 6	$ 41	$ 245
BB+/Ba1 Credit Ratings	$ 231	$ 6	$ 41	$ 278
Full impact of credit contingent contractual obligations	$ 363	$ 16	$ 41	$ 420

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2015, 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 would be required to post $8 million with affiliated parties.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. 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 facility.

In connection with Global Holding's term loan facility, a portion of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with each of FEV's and WMB Marketing Ventures,LLC's 33-1/3% membership interests in Global Holding, are pledged to the lenders under Global Holding's facility as collateral. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FirstEnergy to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 8, Variable Interest Entities, and Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

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 Unit 1 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 $950 million as of December 31, 2015 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback

arrangement expiring in 2040. 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.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. In November 2014, NG repurchased lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term.

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 assets and liabilities as of December 31, 2015 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2016	2017	2018	2019	2020	Thereafter	Total
				(In millions)			
Prices actively quoted[1]	$ (6)	$ 1	$ —	$ —	$ —	$ —	$ (5)
Other external sources[2]	18	(1)	(21)	(26)	—	—	(30)
Prices based on models	(4)	2	—	—	(7)	—	(9)
Total[3]	$ 8	$ 2	$ (21)	$ (26)	$ (7)	$ —	$ (44)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(136) million in non-hedge derivative contracts that are primarily related to NUG contracts at certain of the Utilities. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts as of December 31, 2015, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next 12 months.

Equity Price Risk

As of December 31, 2015, the FirstEnergy pension and OPEB plan assets were approximately allocated as follows: 41% in equity securities, 35% in fixed income securities, 6% in absolute return strategies, 10% in real estate and 8% in cash and short-term securities. A decline in the value of 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, 2015, FirstEnergy made a $143 million contribution to its qualified pension plan. See Note 3, Pension and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2015, FirstEnergy's pension plan and OPEB assets incurred losses of $(172) million, or (2.7)%, 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, 2015, approximately 68% of the funds were invested in fixed income securities, 25% of the funds were invested in equity securities and 7% 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 $1,552 million, $576 million and $147 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2015, excluding $7 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $58 million reduction in fair value as of December 31, 2015. 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 funds or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2015, FirstEnergy contributed approximately $15 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	2016	2017	2018	2019	2020	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 5	$ 2	$ —	$ —	$ —	$ 1,794	$ 1,801	$ 1,802
Average interest rate	8.9%	8.9%	—%	—%	—%	3.6%	3.6%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 660	$ 1,517	$ 1,330	$ 1,035	$ 541	$ 13,867	$ 18,950	$ 20,225
Average interest rate	5.5%	6.1%	4.8%	6.5%	5.5%	5.2%	5.3%	
Variable rate	$ —	$ 2	$ 6	$ 1,000	$ 200	$ 86	$ 1,294	$ 1,294
Average interest rate	—%	3.5%	—%	2.2%	1.9%	—%	2.0%	

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 specific 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. The majority of FirstEnergy's energy contract counterparties maintain investment-grade credit ratings.

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 any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

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 SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. 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. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses 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 required 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's responsive filings 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 require 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. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

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 is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and 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 March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel’s Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior 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);
- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;
- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations 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 FERC proceedings;
- 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, Ohio's renewable energy and energy efficiency standard, 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.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015.The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing

on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;
- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR 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. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio

plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

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, which is still pending. The matter has not been scheduled for oral argument.

Ohio law 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 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. 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. 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 certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, 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 spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies’ existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies’ historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015 and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

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, NG, 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 occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in

appropriate cases “self-reporting” an occurrence to RFC. Moreover, it is clear that 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 electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, 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 advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent “right of first refusal” to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM’s RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

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. While many of the matters involved with the move have been resolved, FERC denied recovery under 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 demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, 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. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for 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 before FERC and certain United States appellate courts On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. 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. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC’s prior ruling rejecting MISO’s proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an “historical looking” approach, where transmission rates reflect actual costs for the prior year, to a “forward looking” approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings. FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

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 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. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller’s violation of FERC’s market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC’s November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a 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 and other parties filed motions to dismiss, which FERC granted. The California Attorney General 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.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to

settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

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.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and 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. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

ENVIRONMENTAL MATTERS

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

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission 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.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), 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. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel 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 plants. 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 plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. 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. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

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. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued 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. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance,

including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become 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.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately

implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

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 the appeal or estimate the possible loss or range of loss.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal 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 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility.

FirstEnergy or its subsidiaries 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 Sheets as of December 31, 2015 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 $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 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 loss 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, 2015, FirstEnergy had approximately $2.3 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 NDTs 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 NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue

operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC's Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

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 FirstEnergy's nuclear facilities.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The 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 14, 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 14, Regulatory Matters for additional information.

FirstEnergy reviews the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Similarly, FirstEnergy records regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. If recovery of a regulatory asset is no longer probable, FirstEnergy will write off that regulatory asset as a charge against earnings.

Pension 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 pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million to its qualified pension plan. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans as of December 31, 2015 was $4.0 billion.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2015, 2014, and 2013 were $369 million ($242 million net of amounts capitalized), $1,243 million ($835 million net of amounts capitalized), and $(396) million ($(256) million net of amounts capitalized), respectively.

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 pension were 4.50%, 4.25% and 5.00% as of December 31, 2015, 2014 and 2013, respectively. The assumed discount rates for OPEB were 4.25%, 4.00% and 4.75% as of December 31, 2015, 2014 and 2013, 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 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $(172) million or (2.7)% compared to $387 million, or 6.2% in 2014 and losses of $(22) million, or (0.3)% in 2013 and assumed a 7.75% rate of return for both years on plan assets which generated $476 million, $496 million and $535 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets 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. The expected return on plan assets for 2016 was lowered to 7.50%.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans. The impact of using the RP2014 mortality table and projection scale SS2014INT resulted in an increase in the projected benefit obligation of $49 million and $1 million for the pension and OPEB plans, respectively, and was included in the 2015 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.50% for pension, 4.25% for OPEB and an estimated return on assets of 7.50%, FirstEnergy expects its 2016 pre-tax net periodic benefit cost (including amounts capitalized) to be approximately $122 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2016). The following table reflects the portion of pension and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2015.

Postemployment Benefits Expense (Credits)	2015	2014	2013
		(In millions)	
Pension	$ 316	$ 939	$ (134)
OPEB	(61)	(101)	(196)
Total	$ 255	$ 838	$ (330)

Health care cost trends continue to increase and will affect future OPEB costs. The 2015 composite health care trend rate assumptions were approximately 6.0-5.5%, compared to 7.5-7.0% in 2014, gradually decreasing to 4.5% 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 effects on 2016 pension and OPEB net periodic benefit costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by .25%	273	19	$ 292
Long-term return on assets	Decrease by .25%	13	1	$ 14
Health care trend rate	Increase by 1.0%	N/A	25	$ 25

Please see Note 3, Pension and Other Postemployment Benefits for additional information.

Long-Lived Assets

FirstEnergy reviews long-lived 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. See Note 1, Organization and Basis of Presentation.

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.

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 the timing of the liability recognition.

AROs as of December 31, 2015, are described further in Note 13, 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. FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. 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 assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50%) 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 or bypasses the qualitative assessment, then the two-step quantitative goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair values of these reporting units were, more likely than not, greater than their carrying values and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- **Future Energy and Capacity Prices:** FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- **Retail Sales and Margin:** FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.
- **Operating and Capital Costs:** FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- **Discount Rate:** A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- **Terminal Value:** A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital, 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

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, ASU 2015-02 "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the

financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to presenting those deferred debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES debt issuance costs included in Deferred Charges and Other Assets were $93 million and $17 million, respectively. FirstEnergy will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In August 2015, the FASB issued ASU 2015 -13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. There was no material effect on FirstEnergy's financial statements resulting from the issuance of ASU 2015-13.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes*",* which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, FirstEnergy and FES reclassified $518 million and $27 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information relating to market risk is set forth in Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 2015 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 eight meetings in 2015.

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 Rules 13a-15(f) and 15d-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 2013, 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, 2015. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 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, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued 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 the accompanying 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.

As discussed in Note 1 to the consolidated financial statements, in 2015 the Company changed the manner in which deferred tax assets and liabilities, along with any related valuation allowance, are classified on the balance sheet.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2016

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions)	For the Years Ended December 31, 2015	2014	2013
REVENUES:			
Electric utilities	$ 10,636	$ 9,871	$ 9,451
Unregulated businesses	4,390	5,178	5,441
Total revenues*	15,026	15,049	14,892
OPERATING EXPENSES:			
Fuel	1,855	2,280	2,496
Purchased power	4,318	4,716	3,963
Other operating expenses	3,749	3,962	3,593
Pension and OPEB mark-to-market adjustment	242	835	(256)
Provision for depreciation	1,282	1,220	1,202
Amortization of regulatory assets, net	268	12	539
General taxes	978	962	978
Impairment of long-lived assets	42	—	795
Total operating expenses	12,734	13,987	13,310
OPERATING INCOME	2,292	1,062	1,582
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	—	(8)	(132)
Investment income (loss)	(22)	72	33
Impairment of equity method investment	(362)	—	—
Interest expense	(1,132)	(1,073)	(1,016)
Capitalized financing costs	117	118	103
Total other expense	(1,399)	(891)	(1,012)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	893	171	570
INCOME TAXES (BENEFITS)	315	(42)	195
INCOME FROM CONTINUING OPERATIONS	578	213	375
Discontinued operations (net of income taxes of $0, $69 and $9, respectively) (Note 19)	—	86	17
NET INCOME	$ 578	$ 299	$ 392
EARNINGS PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90
Basic - Discontinued Operations (Note 19)	—	0.20	0.04
Basic - Net Income	$ 1.37	$ 0.71	$ 0.94
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04
Diluted - Net Income	$ 1.37	$ 0.71	$ 0.94
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	422	420	418
Diluted	424	421	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.44	$ 1.44	$ 1.65

* Includes excise tax collections of $416 million, $420 million and $458 million in 2015, 2014 and 2013, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2015	2014	2013
NET INCOME	$ 578	$ 299	$ 392
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(116)	(76)	(160)
Amortized gains (losses) on derivative hedges	5	(2)	3
Change in unrealized gain on available-for-sale securities	(11)	26	(10)
Other comprehensive loss	(122)	(52)	(167)
Income tax benefits on other comprehensive loss	(47)	(14)	(66)
Other comprehensive loss, net of tax	(75)	(38)	(101)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 503	$ 261	$ 291

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, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 131	$ 85
Receivables-		
Customers, net of allowance for uncollectible accounts of $69 in 2015 and $59 in 2014	1,415	1,554
Other, net of allowance for uncollectible accounts of $5 in 2015 and 2014	180	225
Materials and supplies, at average cost	785	817
Prepaid taxes	135	128
Derivatives	157	159
Collateral	70	230
Other	167	160
	3,040	3,358
PROPERTY, PLANT AND EQUIPMENT:		
In service	49,952	47,484
Less — Accumulated provision for depreciation	15,160	14,150
	34,792	33,334
Construction work in progress	2,422	2,449
	37,214	35,783
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,282	2,341
Other	506	881
	2,788	3,222
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,348	1,411
Other	1,379	1,456
	9,145	9,285
	$ 52,187	$ 51,648
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,166	$ 804
Short-term borrowings	1,708	1,799
Accounts payable	1,075	1,279
Accrued taxes	519	490
Accrued compensation and benefits	334	329
Derivatives	106	167
Other	694	693
	5,602	5,561
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 423,560,397 and 421,102,570 shares outstanding as of December 31, 2015 and December 31, 2014, respectively	42	42
Other paid-in capital	9,952	9,847
Accumulated other comprehensive income	171	246
Retained earnings	2,256	2,285
Total common stockholders' equity	12,421	12,420
Noncontrolling interest	1	2
Total equity	12,422	12,422
Long-term debt and other long-term obligations	19,192	19,176
	31,614	31,598
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,773	6,539
Retirement benefits	4,245	3,932
Asset retirement obligations	1,410	1,387
Deferred gain on sale and leaseback transaction	791	824
Adverse power contract liability	197	217
Other	1,555	1,590
	14,971	14,489
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$ 52,187	$ 51,648

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		Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
	Number of Shares	Par Value			
	418,216,437	$ 42	$ 9,769	$ 385	$ 2,888
Net income					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)	
Pension 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
Net income					299
Amortized gains on derivative hedges, net of $1 million of income tax benefits				(1)	
Change in unrealized gain on investments, net of $10 million of income taxes				16	
Pension and OPEB, net of $23 million of income tax benefits (Note 3)				(53)	
Stock-based compensation			20		
Cash dividends declared on common stock					(604)
Stock issuance - employee benefits	2,474,011		51		
Balance, December 31, 2014	421,102,570	42	9,847	246	2,285
Net income					578
Amortized gains on derivative hedges, net of $1 million of income taxes				4	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(7)	
Pension and OPEB, net of $44 million of income tax benefits (Note 3)				(72)	
Stock-based compensation			45		
Cash dividends declared on common stock					(607)
Stock issuance - employee benefits	2,457,827		60		
Balance, December 31, 2015	423,560,397	$ 42	$ 9,952	$ 171	$ 2,256

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 578	$ 299	$ 392
Adjustments to reconcile net income to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel, regulatory assets, net, and customer intangible amortization	1,836	1,563	2,022
Impairments of long-lived assets	42	—	795
Investment impairment, including equity method investment	464	37	90
Pension and OPEB mark-to-market adjustment	242	835	(256)
Deferred income taxes and investment tax credits, net	284	162	243
Deferred costs on sale leaseback transaction, net	48	48	48
Deferred purchased power and other costs	(105)	(115)	(76)
Asset removal costs charged to income	55	28	20
Retirement benefits	(20)	(53)	(168)
Commodity derivative transactions, net (Note 10)	(73)	64	(3)
Pension trust contributions	(143)	—	—
Gain on sale of investment securities held in trusts	(23)	(64)	(56)
Loss on debt redemptions	—	8	132
Make-whole premiums paid on debt redemptions	—	—	(187)
Lease payments on sale and leaseback transaction	(131)	(137)	(136)
Income from discontinued operations (Note 19)	—	(86)	(17)
Changes in current assets and liabilities-			
Receivables	184	139	(114)
Materials and supplies	(15)	(65)	96
Prepayments and other current assets	(10)	126	(126)
Accounts payable	(243)	42	(25)
Accrued taxes	29	(165)	85
Accrued interest	(6)	31	(10)
Accrued compensation and benefits	5	(22)	19
Other current liabilities	75	23	(62)
Cash collateral, net	140	(54)	(36)
Other	234	69	(8)
Net cash provided from operating activities	3,447	2,713	2,662
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,311	4,528	3,745
Short-term borrowings, net	—	—	1,435
Redemptions and Repayments-			
Long-term debt	(879)	(1,759)	(3,600)
Short-term borrowings, net	(91)	(1,605)	—
Tender premiums paid on debt redemptions	—	—	(110)
Common stock dividend payments	(607)	(604)	(920)
Other	(13)	(47)	(73)
Net cash (used for) provided from financing activities	(279)	513	477
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,704)	(3,312)	(2,638)
Nuclear fuel	(190)	(233)	(250)
Proceeds from asset sales	20	394	4
Sales of investment securities held in trusts	1,534	2,133	2,047
Purchases of investment securities held in trusts	(1,648)	(2,236)	(2,096)
Cash investments	7	35	(23)
Asset removal costs	(142)	(153)	(146)
Other	1	13	9
Net cash used for investing activities	(3,122)	(3,359)	(3,093)
Net change in cash and cash equivalents	46	(133)	46
Cash and cash equivalents at beginning of period	85	218	172
Cash and cash equivalents at end of period	$ 131	$ 85	$ 218
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$ 1,028	$ 931	$ 969
Income taxes (received), net of refunds	$ 37	$ (103)	$ 36

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. FE'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, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI and TrAIL), and AESC. In addition, FE holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

FirstEnergy and its subsidiaries are involved in the generation, transmission, and distribution of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, serving six million customers in the Midwest and Mid-Atlantic regions. Its generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,000 miles of lines and two regional transmission operation centers.

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 necessarily 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 as appropriate. 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.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, AGC, 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, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets by Source	December 31, 2015	December 31, 2014	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 185	$ 240	$ (55)
Customer receivables for future income taxes	355	370	(15)
Nuclear decommissioning and spent fuel disposal costs	(272)	(305)	33
Asset removal costs	(372)	(254)	(118)
Deferred transmission costs	115	90	25
Deferred generation costs	243	281	(38)
Deferred distribution costs	335	182	153
Contract valuations	186	153	33
Storm-related costs	403	465	(62)
Other	170	189	(19)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,348	$ 1,411	$ (63)

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of December 31, 2015 and 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

As of December 31, 2015 and December 31, 2014, FirstEnergy had approximately $116 million and $243 million 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' 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, 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, FirstEnergy accrues the estimated unbilled amount as revenue and reverses 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. There was no material concentration of receivables as of December 31, 2015 and 2014 with respect to any particular segment of FirstEnergy’s customers. Billed and unbilled customer receivables as of December 31, 2015 and 2014 are included below.

Customer Receivables	FirstEnergy	FES
	(In millions)	
December 31, 2015		
Billed	$ 836	$ 165
Unbilled	579	110
Total	$ 1,415	$ 275
December 31, 2014		
Billed	$ 914	$ 239
Unbilled	640	176
Total	$ 1,554	$ 415

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	2015	2014	2013
	(In millions, except per share amounts)		
Income from continuing operations available to common shareholders	$ 578	$ 213	$ 375
Discontinued operations (Note 19)	—	86	17
Net income	$ 578	$ 299	$ 392
Weighted average number of basic shares outstanding	422	420	418
Assumed exercise of dilutive stock options and awards[(1)]	2	1	1
Weighted average number of diluted shares outstanding	424	421	419
Earnings per share:			
Basic earnings per share:			
Continuing operations	$ 1.37	$ 0.51	$ 0.90
Discontinued operations (Note 19)	—	0.20	0.04
Earnings per basic share	$ 1.37	$ 0.71	$ 0.94
Diluted earnings per share:			
Continuing operations	$ 1.37	$ 0.51	$ 0.90
Discontinued operations (Note 19)	—	0.20	0.04
Earnings per diluted share	$ 1.37	$ 0.71	$ 0.94

(1) For the years ended December 31, 2015, 2014 and 2013, approximately one million, two million, and two million shares were excluded from the calculation of diluted shares outstanding, respectively, as their inclusion would be antidilutive.

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 the CES segment's Property, plant and equipment and charged to fuel expense using the specific identification method. The cost of nuclear fuel included in CES' net plant as of December 31, 2015 was $418 million. Net plant in service balances by segment as of December 31, 2015 and 2014 were as follows:

Property, Plant and Equipment	December 31, 2015			December 31, 2014		
	In Service[2]	Accum. Depr.	Net Plant	In Service[2]	Accum. Depr.	Net Plant
			(In millions)			
Regulated Distribution	$ 24,553	$ (7,058)	$ 17,495	$ 23,973	$ (6,759)	$ 17,214
Regulated Transmission	7,703	(1,647)	6,056	6,634	(1,595)	5,039
Competitive Energy Services[1]	17,214	(6,213)	11,001	16,442	(5,598)	10,844
Corporate/Other	482	(242)	240	435	(198)	237
Total	$ 49,952	$ (15,160)	$ 34,792	$ 47,484	$ (14,150)	$ 33,334

[1] Primarily consists of generating assets and nuclear fuel as discussed above.
[2] Includes capital leases of $253 million and $281 million at December 31, 2015 and 2014, respectively.

The major classes of Property, plant and equipment are largely consistent with the segment disclosures above, with the exception of Regulated Distribution, which has approximately $2.0 billion of regulated generation net plant in service.

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 2015, 2014 and 2013 are shown in the following table:

	Annual Composite Depreciation Rate		
	2015	2014	2013
FirstEnergy	2.5%	2.5%	2.6%
FES	3.2%	3.1%	3.1%

For the years ended December 31, 2015, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $49 million, $49 million and $28 million, respectively, of allowance for equity funds used during construction and $68 million, $69 million and $75 million, respectively, of capitalized interest.

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,003 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 $666 million representing AGC's share in this facility as of December 31, 2015 of which $484 million is unregulated and included within the CES segment. 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 Statements 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.

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 the timing of the liability recognition.

AROs as of December 31, 2015, are described further in Note 13, Asset Retirement Obligations.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived 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.

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. In connection with the transaction, 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 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. The impairment charge recognized in 2013 is included within the results of the Regulated Distribution segment.

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the Hatfield's Ferry, generating Units 1-3, and Mitchell, generating units 2-3. As a result of this decision 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 recognized in 2013 is included within the results of the CES segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

During 2015, FirstEnergy recognized impairments totaling $42 million associated with certain non-core assets, including equipment and facilities. The impairment charges are included within the Regulated Distribution segment ($8 million) and the CES segment ($34 million).

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.

FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, and CES. The following table presents goodwill by reporting unit:

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Consolidated
	(In millions)			
Balance as of December 31, 2015	$ 5,092	$ 526	$ 800	$ 6,418

There were no changes in goodwill for any reporting unit during 2015. As of December 31, 2015 and 2014, total goodwill recognized by FES was $23 million. Neither FirstEnergy nor FES has accumulated impairment charges as of December 31, 2015.

Annual impairment testing is conducted as of July 31 of each year and for 2015, 2014 and 2013, the analysis indicated no impairment of goodwill. For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- **Future Energy and Capacity Prices:** FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- **Retail Sales and Margin:** FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.

- **Operating and Capital Costs:** FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- **Discount Rate:** A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- **Terminal Value:** A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital and revised environmental requirements could have a negative impact on future goodwill assessments.

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. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset in net regulatory assets. In 2015, 2014 and 2013, FirstEnergy recognized $102 million, $37 million and $90 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $90 million, $33 million and $79 million, respectively. The fair values of FirstEnergy's investments are disclosed in Note 9, Fair Value Measurements.

FirstEnergy holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. In 2015, Global Holding incurred losses primarily as a result of declines in coal prices due to weakening global and U.S. coal demand. Based on the significant decline in coal pricing and the current outlook for the coal market, including the significant decline in the market capitalization of coal companies in 2015, FirstEnergy assessed the value of its investment in Global Holding and determined there was a decline in the fair value of the investment below its carrying value that was other than temporary, resulting in an a pre-tax impairment charge of $362 million. Key assumptions incorporated into the discounted cash flow analysis utilized in the impairment analysis included the discount rate, future long term coal prices, production levels, sales forecasts, projected capital and operating costs. The impairment charge is classified as a component of Other Income (Expense) in the Consolidated Statement of Income. See Note 8, Variable Interest Entities, for further discussion of FirstEnergy's investment in Global Holding.

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

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, ASU 2015-02 "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to presenting those deferred debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES debt issuance costs included in Deferred Charges and Other Assets were $93 million and $17 million, respectively. FirstEnergy will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In August 2015, the FASB issued ASU 2015 -13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. There was no material effect on FirstEnergy's financial statements resulting from the issuance of ASU 2015-13.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes", which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, FirstEnergy and FES reclassified $518 million and $27 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

2. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the years ended December 31, 2015, 2014 and 2013 for FirstEnergy are shown in the following table:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2013	$ (38)	$ 15	$ 408	$ 385
Other comprehensive income before reclassifications	—	46	35	81
Amounts reclassified from AOCI	3	(56)	(195)	(248)
Other comprehensive income (loss)	3	(10)	(160)	(167)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(63)	(66)
Other comprehensive income (loss), net of tax	2	(6)	(97)	(101)
AOCI Balance, December 31, 2013	$ (36)	$ 9	$ 311	$ 284
Other comprehensive income before reclassifications	—	89	92	181
Amounts reclassified from AOCI	(2)	(63)	(168)	(233)
Other comprehensive income (loss)	(2)	26	(76)	(52)
Income tax (benefits) on other comprehensive income (loss)	(1)	10	(23)	(14)
Other comprehensive income (loss), net of tax	(1)	16	(53)	(38)
AOCI Balance, December 31, 2014	$ (37)	$ 25	$ 258	$ 246
Other comprehensive income before reclassifications	—	14	10	24
Amounts reclassified from AOCI	5	(25)	(126)	(146)
Other comprehensive income (loss)	5	(11)	(116)	(122)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(44)	(47)
Other comprehensive income (loss), net of tax	4	(7)	(72)	(75)
AOCI Balance, December 31, 2015	$ (33)	$ 18	$ 186	$ 171

The following amounts were reclassified from AOCI for FirstEnergy in the years ended December 31, 2015, 2014 and 2013:

FirstEnergy

Reclassifications from AOCI [2]	Year Ended December 31, 2015	2014	2013	Affected Line Item in Consolidated Statements of Income
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (3)	$ (10)	$ (8)	Other operating expenses
Long-term debt	8	8	11	Interest expense
	5	(2)	3	Total before taxes
	(1)	1	(1)	Income taxes (benefits)
	$ 4	$ (1)	$ 2	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (25)	$ (63)	$ (56)	Investment income (loss)
	9	24	21	Income taxes (benefits)
	$ (16)	$ (39)	$ (35)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (126)	$ (168)	$ (195)	[1]
	49	65	75	Income taxes (benefits)
	$ (77)	$ (103)	$ (120)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

The changes in AOCI for the years ended December 31, 2015, 2014 and 2013 for FES are shown in the following table:

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2013	$ 3	$ 13	$ 56	$ 72
Other comprehensive income before reclassifications	—	41	5	46
Amounts reclassified from AOCI	(6)	(49)	(20)	(75)
Other comprehensive loss	(6)	(8)	(15)	(29)
Income tax benefits on other comprehensive loss	(2)	(3)	(6)	(11)
Other comprehensive loss, net of tax	(4)	(5)	(9)	(18)
AOCI Balance, December 31, 2013	$ (1)	$ 8	$ 47	$ 54
Other comprehensive income before reclassifications	—	80	13	93
Amounts reclassified from AOCI	(10)	(59)	(19)	(88)
Other comprehensive income (loss)	(10)	21	(6)	5
Income tax (benefits) on other comprehensive income (loss)	(4)	8	(2)	2
Other comprehensive income (loss), net of tax	(6)	13	(4)	3
AOCI Balance, December 31, 2014	$ (7)	$ 21	$ 43	$ 57
Other comprehensive income before reclassifications	—	15	10	25
Amounts reclassified from AOCI	(3)	(24)	(16)	(43)
Other comprehensive loss	(3)	(9)	(6)	(18)
Income tax benefits on other comprehensive loss	(1)	(4)	(2)	(7)
Other comprehensive loss, net of tax	(2)	(5)	(4)	(11)
AOCI Balance, December 31, 2015	$ (9)	$ 16	$ 39	$ 46

The following amounts were reclassified from AOCI for FES in the years ended December 31, 2015, 2014 and 2013:

FES

Reclassifications from AOCI [2]	Year Ended December 31, 2015	2014	2013	Affected Line Item in Consolidated Statements of Income
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (3)	$ (10)	$ (8)	Other operating expenses
Long-term debt	—	—	2	Interest expense - other
	(3)	(10)	(6)	Total before taxes
	1	4	2	Income taxes (benefits)
	$ (2)	$ (6)	$ (4)	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (24)	$ (59)	$ (49)	Investment income (loss)
	9	22	18	Income taxes (benefits)
	$ (15)	$ (37)	$ (31)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (16)	$ (19)	$ (20)	[1]
	6	7	8	Income taxes (benefits)
	$ (10)	$ (12)	$ (12)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

3. PENSION 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 pension 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. In 2014, the qualified pension plan was amended authorizing a voluntary cashout window program for certain eligible terminated participants with vested benefits. Payment of benefits for participants that elected an immediate lump sum cash payment or an annuity resulted in a $40 million reduction to the underfunded status of the pension plan. Additionally, during 2015 and 2014, certain unions ratified their labor agreements that ended subsidized retiree health care resulting in a reduction to the OPEB benefit obligation by approximately $10 million and $97 million, respectively.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2015, 2014, and 2013 were $369 million ($242 million net of amounts capitalized), $1,243 million ($835 million net of amounts capitalized), and $(396) million ($(256) million net of amounts capitalized), respectively. In 2015, the pension and OPEB mark-to-market adjustment primarily reflects lower than expected asset returns as well as the impact of other demographic assumptions, including revisions to mortality assumptions, partially offset by a 25 basis point increase in the discount rate.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million to its qualified pension plan. In 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions.

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.

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 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $(172) million, or (2.7)% compared to earnings of $387 million, or 6.2% in 2014 and losses of $(22) million, or (0.3)% in 2013, and assumed a 7.75% rate of return for each year on plan assets which generated $476 million, $496 million and $535 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets 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.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans. The impact of using the RP2014 mortality table and projection scale SS2014INT resulted in an increase in the projected benefit obligation of $49 million and $1 million for the pension and OPEB plans, respectively, and was included in the 2015 pension and OPEB mark-to-market adjustment.

Obligations and Funded Status	Pension		OPEB	
	2015	2014	2015	2014
		(In millions)		
Change in benefit obligation:				
Benefit obligation as of January 1	$ 9,249	$ 8,263	$ 757	$ 879
Service cost	193	167	5	9
Interest cost	383	402	29	39
Plan participants' contributions	—	—	6	16
Plan amendments	—	5	(10)	(97)
Medicare retiree drug subsidy	—	—	1	—
Actuarial (gain) loss	(277)	1,123	(2)	13
Benefits paid	(469)	(711)	(62)	(102)
Benefit obligation as of December 31	$ 9,079	$ 9,249	$ 724	$ 757
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$ 5,824	$ 6,171	$ 464	$ 495
Actual return (losses) on plan assets	(178)	349	6	38
Company contributions	161	15	17	17
Plan participants' contributions	—	—	6	16
Benefits paid	(469)	(711)	(62)	(102)
Fair value of plan assets as of December 31	$ 5,338	$ 5,824	$ 431	$ 464
Funded Status:				
Qualified plan	$ (3,366)	$ (3,064)		
Non-qualified plans	(375)	(361)		
Funded Status	$ (3,741)	$ (3,425)	$ (293)	$ (293)
Accumulated benefit obligation	$ 8,579	$ 8,744	$ —	$ —
Amounts Recognized on the Balance Sheet:				
Current liabilities	$ (18)	$ (17)	$ —	$ —
Noncurrent liabilities	(3,723)	(3,408)	(293)	(293)
Net liability as of December 31	$ (3,741)	$ (3,425)	$ (293)	$ (293)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$ 37	$ 45	$ (355)	$ (479)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	4.50%	4.25%	4.25%	4.00%
Rate of compensation increase	4.20%	4.20%	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	6.0-5.5%	7.5-7.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.5%	4.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2026	2026
Allocation of Plan Assets (as of December 31)				
Equity securities	40%	36%	51%	49%
Bonds	34%	33%	43%	40%
Absolute return strategies	7%	14%	—%	1%
Real estate	11%	7%	—%	1%
Derivatives	—%	1%	—%	—%
Cash and short-term securities	8%	9%	6%	9%
Total	100%	100%	100%	100%

The estimated 2016 amortization of pension and OPEB prior service costs (credits) from AOCI into net periodic pension and OPEB costs (credits) is approximately $8 million and $(80) million, respectively.

Components of Net Periodic Benefit Costs	Pension			OPEB		
	2015	2014	2013	2015	2014	2013
	(In millions)					
Service cost	$ 193	$ 167	$ 197	$ 5	$ 9	$ 13
Interest cost	383	402	372	29	39	37
Expected return on plan assets	(443)	(462)	(501)	(33)	(34)	(34)
Amortization of prior service cost (credit)	8	8	12	(134)	(176)	(207)
Pension & OPEB mark-to-market adjustment	344	1,235	(267)	25	8	(129)
Net periodic cost (credit)	$ 485	$ 1,350	$ (187)	$ (108)	$ (154)	$ (320)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension			OPEB		
	2015	2014	2013	2015	2014	2013
Weighted-average discount rate	4.25%	5.00%	4.25%	4.00%	4.75%	4.00%
Expected long-term return on plan assets	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
Rate of compensation increase	4.20%	4.20%	4.70%	N/A	N/A	N/A

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 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. In 2016, FirstEnergy decreased the expected long-term return on plan assets to 7.50%.

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 2015 and 2014.

	December 31, 2015				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 427	$ —	$ 427	8%
Equity investments					
Domestic	869	75	—	944	18%
International	395	794	—	1,189	22%
Fixed income					
Government bonds	—	232	—	232	4%
Corporate bonds	—	1,115	—	1,115	21%
High yield debt	—	438	—	438	8%
Mortgage-backed securities (non-government)	—	31	—	31	1%
Alternatives					
Hedge funds (Absolute return)	—	343	—	343	7%
Derivatives	—	15	—	15	—%
Private equity funds	—	—	24	24	—%
Real estate funds	—	—	587	587	11%
Total [1]	$ 1,264	$ 3,470	$ 611	$ 5,345	100%

[1] Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2014				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 517	$ —	$ 517	9%
Equity investments					
Domestic	1,266	8	—	1,274	22%
International	355	414	—	769	14%
Fixed income					
Government bonds	—	159	—	159	3%
Corporate bonds	—	1,386	—	1,386	24%
High yield debt	—	300	—	300	5%
Mortgage-backed securities (non-government)	—	37	—	37	1%
Alternatives					
Hedge funds (Absolute return)	—	809	—	809	14%
Derivatives	—	35	—	35	1%
Private equity funds	—	—	25	25	—%
Real estate funds	—	—	421	421	7%
Total [1]	$ 1,621	$ 3,665	$ 446	$ 5,732	100%

[1] Excludes $92 million as of December 31, 2014 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 2015 and 2014:

	Private Equity Funds	Real Estate Funds
	(In millions)	
Balance as of January 1, 2014	$ 27	$ 385
Actual return on plan assets:		
Unrealized gains (losses)	(2)	17
Realized gains	1	14
Transfers in (out)	(1)	5
Balance as of December 31, 2014	$ 25	$ 421
Actual return on plan assets:		
Unrealized gains	—	42
Realized gains (losses)	(1)	16
Transfers in	—	108
Balance as of December 31, 2015	$ 24	$ 587

As of December 31, 2015 and 2014, the OPEB trust investments measured at fair value were as follows:

	December 31, 2015				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 25	$ —	$ 25	6%
Equity investment					
Domestic	219	—	—	219	50%
International	1	3	—	4	1%
Fixed income					
U.S. treasuries	—	42	—	42	10%
Government bonds	—	114	—	114	26%
Corporate bonds	—	27	—	27	6%
High yield debt	—	1	—	1	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	1	—	1	—%
Real estate funds	—	—	2	2	—%
Total [1]	$ 220	$ 216	$ 2	$ 438	100%

[1] Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2014				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 41	$ —	$ 41	9%
Equity investment					
Domestic	230	—	—	230	48%
International	3	3	—	6	1%
Fixed income					
U.S. treasuries	—	41	—	41	9%
Government bonds	—	110	—	110	23%
Corporate bonds	—	32	—	32	7%
High yield debt	—	2	—	2	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	5	—	5	1%
Real estate funds	—	—	3	3	1%
Total [1]	$ 233	$ 237	$ 3	$ 473	100%

[1] Excludes $(9) million as of December 31, 2014, 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 2015 and 2014:

	Real Estate Funds
Balance as of January 1, 2014	$ 5
Transfers out	(2)
Balance as of December 31, 2014	$ 3
Transfers out	(1)
Balance as of December 31, 2015	$ 2

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 pension and OPEB trust portfolios for 2015 and 2014 are shown in the following table:

Target Asset Allocations		
	2015	2014
Equities	38%	42%
Fixed income	30%	32%
Absolute return strategies	8%	14%
Real estate	10%	5%
Alternative investments	8%	1%
Cash	6%	6%
	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:

		OPEB	
	Pension	Benefit Payments	Subsidy Receipts
		(In millions)	
2016	$ 484	$ 54	$ (3)
2017	505	54	(3)
2018	522	54	(3)
2019	533	54	(3)
2020	551	54	(3)
Years 2021-2025	2,946	259	(9)

FES' share of the pension and OPEB net (liability) asset as of December 31, 2015 and 2014, was as follows:

	Pension		OPEB	
	2015	2014	2015	2014
	(In millions)			
Net (Liability) Asset	$ (303)	$ (295)	$ 25	$ 10

FES' share of the net periodic benefit cost (credit), including the pension and OPEB mark-to-market adjustment, for the three years ended December 31, 2015 was as follows:

	Pension			OPEB		
	2015	2014	2013	2015	2014	2013
	(In millions)					
Net Periodic Cost (Credit)	$ 10	$ 150	$ (30)	$ (22)	$ (24)	$ (40)

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy grants stock-based awards through the ICP 2015, primarily in the form of restricted stock and performance-based restricted stock units. Under FirstEnergy's previous incentive compensation plan, the ICP 2007, FirstEnergy also granted stock options and performance shares. The ICP 2007 and ICP 2015 include shareholder authorization to issue 29 million shares and 10 million shares, respectively, of common stock or their equivalent. As of December 31, 2015, approximately 9.9 million shares were available for future grants under the ICP 2015 assuming maximum performance metrics are achieved for the outstanding cycles of restricted stock units. No shares are available for future grants under the ICP 2007. Any shares not issued due to forfeitures or cancellations are added back to the ICP 2015. Shares used under the ICP 2007 and ICP 2015 are issued from authorized but unissued common stock. Vesting periods range from one to ten years, with the majority of awards having a vesting period of three years. FirstEnergy also issues stock through its 401(k) Savings Plan, EDCP, and DCPD. FirstEnergy records the compensation costs for stock-based compensation awards that will be paid in stock over the vesting period based on the fair value on the grant date, less estimated forfeitures. FirstEnergy adjusts the compensation costs for stock-based compensation awards that will be paid in cash based on changes in the fair value of the award as of each reporting date. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or settled. Realized tax benefits during the years ended December 31, 2015, 2014 and 2013 were $10 million, $13 million and $13 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as a financing activity on the Consolidated Statements of Cash Flows.

Stock-based compensation costs 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	**2015**	**2014**	**2013**
		(In millions)	
Restricted Stock Units	$ 46	$ 26	$ 36
Restricted Stock	2	5	6
Performance Shares	—	5	(10)
401(k) Savings Plan	38	25	25
EDCP & DCPD	3	8	3
Total	$ 89	$ 69	$ 60
Stock-based compensation costs capitalized	$ 32	$ 23	$ 20

FES	Years ended December 31,		
Stock-based Compensation Plan	**2015**	**2014**	**2013**
		(In millions)	
Restricted Stock Units	$ 6	$ 4	$ 6
Performance Shares	—	1	(1)
401(k) Savings Plan	5	4	4
Total	$ 11	$ 9	$ 9
Stock-based compensation costs capitalized	$ 1	$ 1	$ 1

Stock option expense was not material for FirstEnergy or FES for the years December 31, 2015, 2014 or 2013. Income tax benefits associated with stock based compensation plan expense were $12 million, $14 million and $23 million (FES - $2 million, $2 million and $1 million) for the years ended 2015, 2014 and 2013, respectively.

Restricted Stock Units

Beginning with the performance-based restricted stock units granted in 2015, two-thirds will be paid in stock and one-third will be paid in cash. Prior to 2015, all performance-based restricted stock units were paid in stock. Restricted stock units paid in stock provide the participant 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. The grant date fair value of the stock portion of the restricted stock unit award is measured based on the average of the high and low prices of FE common stock on the date of grant. Compensation expense is recognized for the grant date fair value of awards that are expected to vest. Restricted stock units paid in cash provide the participant the right to receive cash based on the numbers of stock units set forth in the agreement and value of the equivalent number of shares of FE common stock as of the vesting date. The cash portion of the restricted stock unit award is considered a liability award, which is remeasured each period based on FE's stock price and projected performance adjustments. The liability recorded for cash performance based restricted stock units as of December 31, 2015 was $3 million. No cash was paid to settle the restricted stock unit obligations in 2015. The vesting period for each of the awards was three years. Dividend equivalents are received on the restricted stock units and are reinvested in additional restricted stock units and subject to the same performance conditions.

Restricted stock unit activity for the year ended December 31, 2015, was as follows:

Restricted Stock Unit Activity	Shares	Weighted-Average Grant Date Fair Value
Nonvested as of January 1, 2015	2,069,518	$ 37.65
Granted in 2015	1,157,755	35.27
Forfeited in 2015	(231,271)	34.19
Vested in 2015[(1)]	(559,114)	44.58
Nonvested as of December 31, 2015	2,436,888	$ 35.26

[(1)] Excludes dividend equivalents of 89,681 earned during vesting period

The weighted average fair value of awards granted in 2015, 2014 and 2013 were $35.27, $32.17 and $39.90 respectively. For the years ended December 31, 2015, 2014, and 2013, the fair value of restricted stock units vested was $22 million, $28 million, and $37 million, respectively. As of December 31, 2015, there was $32 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock units; that cost is expected to be recognized over a period of approximately two years.

Restricted Stock

Certain employees receive awards of FE restricted stock (as opposed to "units" with the right to receive shares at the end of the restriction period) subject to restrictions that lapse over a defined period of time or upon achieving performance results. The fair value of restricted stock is measured based on the average of the high and low prices of FirstEnergy common stock on the date of grant. Dividends are received on the restricted stock and are reinvested in additional shares of restricted stock.

Restricted common stock (restricted stock) activity for the year ended December 31, 2015, was as follows:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2015	342,286	$ 45.29
Granted in 2015	65,434	32.98
Forfeited in 2015	(26,079)	57.58
Vested in 2015[(1)]	(190,985)	43.17
Nonvested as of December 31, 2015	190,656	$ 40.65

[(1)] Excludes 52,872 shares for dividends earned during vesting period

The weighted average vesting period for restricted stock granted in 2015 was 5.59 years. The weighted average fair value of awards granted in 2015, 2014, and 2013 were $32.98, $32.71 and $42.53 respectively. For the years ended December 31, 2015, 2014, and 2013, the fair value of restricted stock vested was $8 million, $4 million, and $7 million, respectively. As of December 31, 2015, there was $3 million of total unrecognized compensation cost related to non-vested restricted stock, which is expected to be recognized over a period of approximately three years.

Stock Options

Stock options have been granted to certain employees allowing them to purchase a specified number of common shares at a fixed exercise price over a defined period of time. Stock options generally expire ten years from the date of grant. There were no stock options granted in 2015. Stock option activity during 2015 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2015 (1,077,988 options exercisable)	1,439,145	$ 44.83
Options exercised	(18,551)	29.53
Options forfeited	(8,623)	68.02
Balance, December 31, 2015 (1,211,358 options exercisable)	1,411,971	$ 44.89

Cash received from the exercise of stock options in 2015, 2014 and 2013 was $1 million, $1 million and $19 million, respectively. The total intrinsic value of options exercised during 2015 was not material. The weighted-average remaining contractual term of options outstanding as of December 31, 2015 was 3.58 years.

Performance Shares

Prior to the 2015 grant of performance-based restricted stock units discussed above, the Company granted performance shares. Performance shares are share equivalents and do not have voting rights. The performance shares outstanding track the performance of FE's common stock over a three-year vesting period. Dividend equivalents accrue on performance shares and are reinvested into additional performance shares with the same performance conditions. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. No performance shares were granted in 2015. In 2014, $3 million cash was paid to settle performance share obligations. During 2015 and 2013, no cash was paid to settle performance shares due to the performance criteria not being met for the previous three-year vesting period.

401(k) Savings Plan

In 2015 and 2014, 1,072,494 and 756,412 shares of FE common stock, respectively, were issued and contributed to participants' accounts. In 2013, approximately 708,000 shares of FE common stock were purchased on the market and contributed to participants' accounts.

EDCP

Under the EDCP, covered employees can defer a portion of their compensation, including base salary, annual incentive awards and/or long-term incentive awards, into unfunded accounts. Annual incentive and long-term incentive awards may be deferred in FE stock accounts. Base salary and annual incentive awards may be deferred into a retirement cash account which earns interest. Dividends are calculated quarterly on stock units outstanding and are credited in the form of additional stock units. The form of payout as stock or cash can vary depending upon the form of the award, the duration of the deferral and other factors. Certain types of deferrals such as dividend equivalent units, Short-Term Incentive Awards, and performance share awards are required to be paid in cash. Until 2015, payouts of the stock accounts typically occurred three years from the date of deferral, although participants could have elected to defer their shares into a retirement stock account that would pay out in cash upon retirement. In 2015, FirstEnergy amended the EDCP to eliminate the right to receive deferred shares after three years, effective for deferrals made on or after November 1, 2015. Awards deferred into a retirement stock account will pay out in cash upon separation from service, death or disability. Interest accrues on the cash allocated to the retirement cash account and the balance will pay out in cash over a time period as elected by the participant.

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 $9 million and $8 million as of December 31, 2015 and December 31, 2014, respectively, is included in the caption “Retirement benefits” on the Consolidated Balance Sheets.

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.

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.

On December 18, 2015, the President signed into law the Protecting Americans from Tax Hikes Act of 2015 (the Act). The Act, among other things, made permanent the R&D tax credit, and also extended accelerated depreciation of qualified capital investments placed into service. This bonus depreciation provision is 50% for qualifying assets placed into service from 2015 through 2017, 40% for qualifying assets placed into service in 2018 and 30% for qualifying assets placed into service in 2019. FirstEnergy and FES recorded the effects of the Act that apply to 2015 in the fourth quarter of 2015. The extension of the tax benefits did not have a significant impact to the effective tax rate.

INCOME TAXES (BENEFITS)[1]	2015	2014	2013
		(In millions)	
FirstEnergy			
Currently payable (receivable)-			
Federal	$ 1	$ (132)	$ (118)
State	30	(72)	70
	31	(204)	(48)
Deferred, net-			
Federal	277	214	305
State	15	(42)	(54)
	292	172	251
Investment tax credit amortization	(8)	(10)	(8)
Total provision for income taxes (benefits)	$ 315	$ (42)	$ 195
FES			
Currently payable (receivable)-			
Federal	$ (56)	$ (222)	$ (300)
State	2	(13)	(3)
	(54)	(235)	(303)
Deferred, net-			
Federal	103	25	317
State	18	(14)	(4)
	121	11	313
Investment tax credit amortization	(2)	(4)	(4)
Total provision for income taxes (benefits)	$ 65	$ (228)	$ 6

[1]Provision for Income Taxes (Benefits) on Income from Continuing Operations. Currently payable (receivable) in 2014 excludes $106 million and $12 million of federal and state taxes, respectively, associated with discontinued operations. Deferred, net in 2014 excludes $44 million and $5 million of federal and state tax benefits, respectively, associated with discontinued operations.

FirstEnergy and FES tax rates are affected by permanent items, such as AFUDC equity and other flow-through items as well as discrete items that may occur in any given period, but are not consistent from period to period. The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total income taxes on continuing operations for the three years ended December 31:

	2015	2014	2013
		(In millions)	
FirstEnergy			
Income from Continuing Operations before income taxes	$ 893	$ 171	$ 570
Federal income tax expense at statutory rate (35%)	$ 313	$ 60	$ 199
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	34	12	10
AFUDC equity and other flow-through	(16)	(13)	(7)
Amortization of investment tax credits	(8)	(10)	(8)
Change in accounting method	(8)	(27)	—
ESOP dividend	(6)	(6)	(9)
Tax basis balance sheet adjustments	—	(25)	—
Uncertain tax positions	1	(35)	(2)
Other, net	5	2	12
Total income taxes (benefits)	$ 315	$ (42)	$ 195
Effective income tax rate	35.3%	(24.6)%	34.2%
FES			
Income (loss) from Continuing Operations before income taxes (benefits)	$ 147	$ (588)	$ 52
Federal income tax expense (benefit) at statutory rate (35%)	$ 51	$ (206)	$ 18
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	16	(14)	(5)
Amortization of investment tax credits	(2)	(4)	(4)
ESOP dividend	(1)	(1)	(2)
Uncertain tax positions	5	—	—
Other, net	(4)	(3)	(1)
Total income taxes (benefits)	$ 65	$ (228)	$ 6
Effective income tax rate	44.2%	38.8 %	11.5%

In 2015, FirstEnergy's effective tax rate was 35.3% compared to (24.6)% in 2014. The increase in the effective tax rate year-over-year resulted from lower tax benefits in 2015 as compared to 2014, primarily related to IRS approved changes in accounting methods, reduced tax benefits on uncertain tax positions, partially offset by lower valuation allowances required on state and municipal net operating loss carryforwards that FirstEnergy believes are no longer realizable. Additionally, during 2014, income tax benefits of $25 million were recorded that related to prior periods. The out-of-period adjustment primarily related to the correction of amounts included in the FirstEnergy's tax basis balance sheet. Management determined that this adjustment was not material to 2014 or any prior period. The increase in the effective rate was also impacted by higher income from continuing operations.

In 2015, FES' effective tax rate on income from continuing operations was 44.2% compared to 38.8% on a loss from continuing operations in 2014. The increase in the effective tax rate is primarily due to an increase in reserves associated with uncertain tax positions in 2015 and the absence of tax benefits recognized in 2014 associated with changes in state apportionment factors, partially offset by lower valuation allowances recorded on state and municipal NOL carryforwards that FirstEnergy believes are no longer realizable.

Accumulated deferred income taxes as of December 31, 2015 and 2014 are as follows:

	2015	2014
	(In millions)	
FirstEnergy		
Property basis differences	$ 9,920	$ 9,354
Deferred sale and leaseback gain	(360)	(381)
Pension and OPEB	(1,541)	(1,433)
Nuclear decommissioning activities	480	458
Asset retirement obligations	(731)	(641)
Regulatory asset/liability	763	768
Loss carryforwards and AMT credits	(1,965)	(1,932)
Loss carryforward valuation reserve	192	174
All other	15	172
Net deferred income tax liability	$ 6,773	$ 6,539
FES		
Property basis differences	$ 1,901	$ 1,749
Deferred sale and leaseback gain	(342)	(356)
Pension and OPEB	(393)	(373)
Lease market valuation liability	95	75
Nuclear decommissioning activities	483	489
Asset retirement obligations	(509)	(486)
Loss carryforwards and AMT credits	(687)	(631)
Loss carryforward valuation reserve	46	32
All other	6	(15)
Net deferred income tax liability	$ 600	$ 484

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state taxing authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2011-2014. In January 2015, the IRS completed its examination of the 2013 federal income tax return and issued a Revenue Agent Report and there were no material impacts to FirstEnergy's effective tax rate associated with this examination. Tax year 2014 is currently under review by the IRS.

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, 2015, the deferred income tax assets, before any valuation allowances, for loss carryforwards and AMT credits consisted of $1.5 billion of Federal NOL carryforwards, net of tax, that will begin to expire in 2030, Federal AMT credits of $26 million, net of tax, that have an indefinite carryforward period, and $398 million, net of tax, of state and local NOL carryforwards that will begin to expire in 2016.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $10 billion for FirstEnergy, of which approximately $6 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
2016-2020	$ 403	$ 2,983	$ 95	$ 1,820
2021-2025	1,323	—	68	—
2026-2030	2,205	—	259	—
2031-2035	3,245	—	1,128	—
	$ 7,176	$ 2,983	$ 1,550	$ 1,820

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. A recognition threshold and measurement attribute is utilized 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, 2015 and 2014, FirstEnergy's total unrecognized income tax benefits were approximately $34 million. If ultimately recognized in future years, approximately $29 million of unrecognized income tax benefits as of December 31, 2015, would impact the effective tax rate. As of December 31, 2015, it is reasonably possible that approximately $9 million of unrecognized tax benefits may be resolved during 2016 as a result of the statute of limitations expiring, of which approximately $7 million would affect FirstEnergy's effective tax rate.

The following table summarizes the changes in unrecognized tax positions for the years ended 2015, 2014 and 2013:

	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2013	$ 43	$ 3
Prior years increases	10	—
Prior years decreases	(5)	—
Balance, December 31, 2013	$ 48	$ 3
Current year increases	4	—
Prior years increases	5	—
Prior years decreases	(23)	—
Balance, December 31, 2014	$ 34	$ 3
Current year increases	3	—
Prior years increases	7	5
Prior years decreases	(10)	—
Balance, December 31, 2015	$ 34	$ 8

FirstEnergy recognizes interest expense or income and penalties related to uncertain tax positions in income taxes. 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's reversal of accrued interest associated with unrecognized tax benefits reduced FirstEnergy's effective tax rate in 2015 and 2014 by approximately $1 million and $6 million, respectively. There was an increase of $1 million of accrued interest for the year ended December 31, 2013.

The following table summarizes the net interest expense (income) for the three years ended December 31, 2015 and the cumulative net interest payable as of December 31, 2015 and 2014 (FES did not have net interest expense (income) or a net interest payable for the periods presented):

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable As of December 31,	
	2015	2014	2013	2015	2014
	(In millions)			*(In millions)*	
FirstEnergy	$ (1)	$ (6)	$ 1	$ 1	$ 2

	2015	2014	2013
		(In millions)	
FirstEnergy			
KWH excise	$ 193	$ 194	$ 219
State gross receipts	224	226	240
Real and personal property	410	393	368
Social security and unemployment	119	112	110
Other	32	37	41
Total general taxes	$ 978	$ 962	$ 978
FES			
State gross receipts	$ 44	$ 69	$ 77
Real and personal property	36	39	40
Social security and unemployment	16	17	19
Other	2	3	2
Total general taxes	$ 98	$ 128	$ 138

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, expiring in 2016. 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 expiring in 2017. OE, CEI and TE 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, expiring in 2040. FES has unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. In 2013, FG acquired the remaining lessor interests in Bruce Mansfield Units 1, 2 and 3, which were part of the leases entered into by CEI and TE in 1987.

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. On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. In November 2014, NG repurchased 55.3 MW of lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. OE and TE continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

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, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

Operating lease expense for 2015, 2014 and 2013, is summarized as follows:

(In millions)	2015	2014	2013
FirstEnergy	$ 174	$ 199	$ 224
FES	$ 94	$ 95	$ 97

The future minimum capital lease payments as of December 31, 2015 are as follows:

Capital leases	FirstEnergy	FES
	(In millions)	
2016	$ 36	$ 6
2017	31	6
2018	24	2
2019	18	—
2020	14	—
Years thereafter	27	—
Total minimum lease payments	150	14
Interest portion	(18)	(1)
Present value of net minimum lease payments	132	13
Less current portion	32	5
Noncurrent portion	$ 100	$ 8

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2015, are as follows:

	FirstEnergy		
Operating Leases	**Lease Payments**	**PNBV**	**Net**
		(In millions)	
2016	$ 197	$ 13	$ 184
2017	122	3	119
2018	135	—	135
2019	116	—	116
2020	91	—	91
Years thereafter	1,438	—	1,438
Total minimum lease payments	$ 2,099	$ 16	$ 2,083

FES' future minimum operating lease payments as of December 31, 2015, are as follows:

Operating Leases	**Lease Payments**
	(In millions)
2016	$ 131
2017	82
2018	101
2019	97
2020	68
Years thereafter	1,315
Total minimum lease payments	$ 1,794

7. INTANGIBLE ASSETS

As of December 31, 2015, 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**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
NUG contracts[1]	$ 124	$ 25	$ 99	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 74
OVEC	54	9	45	2	2	2	2	2	2	35
Coal contracts[2][3][4]	556	430	126	116	38	32	17	17	6	—
FES customer contracts	148	87	61	17	17	16	14	13	1	—
	$ 882	$ 551	$ 331	$ 140	$ 62	$ 55	$ 38	$ 37	$ 14	$ 109

(1) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.

(2) A gross amount of $40 million ($23 million, net) of the coal contracts is related to FES. The 2015 and estimated 2016 to 2019 amortization expense for FES is $5.7 million annually.

(3) A gross amount of $102 million ($16 million, net) of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings. Accordingly, the amortization expense for these coal contracts is excluded from table above.

(4) Amortization expense in 2015, includes a $67 million impairment of a coal contract intangible asset associated with the termination of a coal supply contract, which impacted 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 based on control and economics to determine whether a variable interest classifies FirstEnergy as the primary beneficiary (a controlling financial interest) of a VIE. An enterprise has a controlling financial interest if it has both power and economic control, such that an entity has (i) the power to direct the activities of a VIE that most significantly impact the entity's economic performance, and (ii) 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.

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.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into categories based on similar risk characteristics and significance.

Consolidated VIEs

VIEs in which FirstEnergy is the primary beneficiary consist of the following (included in FirstEnergy's consolidated financial statements):

- ***PNBV*** - PNBV, a business trust established by OE in 1996, issued certain beneficial interests and notes to fund the acquisition of a portion of the bonds issued by certain owner trusts in connection with the sale and leaseback in 1987 of a portion of OE's interest in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. The beneficial ownership of PNBV includes a 3% interest by unaffiliated third parties.

- ***Ohio Securitization*** - In September 2012, the Ohio Companies created separate, wholly-owned limited liability companies (SPEs) which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. As of December 31, 2015 and December 31, 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.

- ***JCP&L Securitization*** - 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, 2015 and December 31, 2014, $128 million and $168 million of the transition bonds were outstanding, respectively.

- ***MP and PE Environmental Funding Companies*** - The entities issued bonds of which the proceeds 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. 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, 2015 and December 31, 2014, $429 million and $450 million of the environmental control bonds were outstanding, respectively.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- ***Global Holding*** - FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint venture's economic performance. FEV's ownership interest is subject to the equity method of accounting. See Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

  As discussed in Note 15, Commitments, Guarantees and Contingencies, FE is the guarantor under Global Holding's $300 million term loan facility. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

- ***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 FE 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 PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting.

- ***Power Purchase Agreements*** - FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities at its Regulated Distribution segment 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 15 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 one of these NUG entities, it does not have a variable interest in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; 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 at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $116 million and $185 million, respectively, during the years ended December 31, 2015 and 2014.

- ***Sale and Leaseback Transactions*** - 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 Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. 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. As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

  On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. Upon the completion of these transactions, NG will have obtained all of the lessor equity interests at Perry Unit 1 and Beaver Valley Unit 2.

  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, 2015:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
		(In millions)	
FirstEnergy	$ 1,225	$ 950	$ 275
FES	$ 1,155	$ 933	$ 222

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 processes for FTRs and NUGs 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 MWHs. 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 MWHs reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWHs. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

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, 2015, from those used as of December 31, 2014. 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, 2015 and 2014. 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, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets			*(In millions)*					
Corporate debt securities	$ —	$ 1,245	$ —	$ 1,245	$ —	$ 1,221	$ —	$ 1,221
Derivative assets - commodity contracts	4	224	—	228	1	171	—	172
Derivative assets - FTRs	—	—	8	8	—	—	39	39
Derivative assets - NUG contracts[1]	—	—	1	1	—	—	2	2
Equity securities[2]	576	—	—	576	592	—	—	592
Foreign government debt securities	—	75	—	75	—	76	—	76
U.S. government debt securities	—	180	—	180	—	182	—	182
U.S. state debt securities	—	246	—	246	—	237	—	237
Other[3]	105	212	—	317	55	256	—	311
Total assets	$ 685	$ 2,182	$ 9	$ 2,876	$ 648	$ 2,143	$ 41	$ 2,832
Liabilities								
Derivative liabilities - commodity contracts	$ (9)	$ (122)	$ —	$ (131)	$ (26)	$ (141)	$ —	$ (167)
Derivative liabilities - FTRs	—	—	(13)	(13)	—	—	(14)	(14)
Derivative liabilities - NUG contracts[1]	—	—	(137)	(137)	—	—	(153)	(153)
Total liabilities	$ (9)	$ (122)	$ (150)	$ (281)	$ (26)	$ (141)	$ (167)	$ (334)
Net assets (liabilities)[4]	$ 676	$ 2,060	$ (141)	$ 2,595	$ 622	$ 2,002	$ (126)	$ 2,498

(1) NUG 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 cash and short-term cash investments.

(4) Excludes $7 million and $40 million as of December 31, 2015 and December 31, 2014, 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 and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2015 and December 31, 2014:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
			(In millions)			
January 1, 2014 Balance	$ 20	$ (222)	$ (202)	$ 4	$ (12)	$ (8)
Unrealized gain (loss)	2	(2)	—	47	(1)	46
Purchases	—	—	—	26	(16)	10
Settlements	(20)	71	51	(38)	15	(23)
December 31, 2014 Balance	$ 2	$ (153)	$ (151)	$ 39	$ (14)	$ 25
Unrealized gain (loss)	2	(49)	(47)	(5)	(7)	(12)
Purchases	—	—	—	22	(11)	11
Settlements	(3)	65	62	(48)	19	(29)
December 31, 2015 Balance	$ 1	$ (137)	$ (136)	$ 8	$ (13)	$ (5)

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

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, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (5)	Model	RTO auction clearing prices	($3.90) to $6.90	$1.00	Dollars/MWH
NUG Contracts	$ (136)	Model	Generation	400 to 3,871,000	839,000	MWH
			Regional electricity prices	$38.10 to $45.60	$40.20	Dollars/MWH

FES

Recurring Fair Value Measurements	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 678	$ —	$ 678	$ —	$ 655	$ —	$ 655
Derivative assets - commodity contracts	4	224	—	228	1	171	—	172
Derivative assets - FTRs	—	—	5	5	—	—	27	27
Equity securities[1]	378	—	—	378	360	—	—	360
Foreign government debt securities	—	59	—	59	—	57	—	57
U.S. government debt securities	—	23	—	23	—	46	—	46
U.S. state debt securities	—	4	—	4	—	4	—	4
Other[2]	—	184	—	184	—	199	—	199
Total assets	$ 382	$ 1,172	$ 5	$ 1,559	$ 361	$ 1,132	$ 27	$ 1,520
Liabilities								
Derivative liabilities - commodity contracts	$ (9)	$ (122)	$ —	$ (131)	$ (26)	$ (141)	$ —	$ (167)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(13)	(13)
Total liabilities	$ (9)	$ (122)	$ (11)	$ (142)	$ (26)	$ (141)	$ (13)	$ (180)
Net assets (liabilities)[3]	$ 373	$ 1,050	$ (6)	$ 1,417	$ 335	$ 991	$ 14	$ 1,340

(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 $1 million and $44 million as of December 31, 2015 and December 31, 2014, 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, 2015 and December 31, 2014:

	Derivative Asset	Derivative Liability	Net Asset/(Liability)
		(In millions)	
January 1, 2014 Balance	$ 3	$ (11)	$ (8)
Unrealized gain (loss)	34	(1)	33
Purchases	15	(16)	(1)
Settlements	(25)	15	(10)
December 31, 2014 Balance	$ 27	$ (13)	$ 14
Unrealized gain (loss)	2	(5)	(3)
Purchases	9	(10)	(1)
Settlements	(33)	17	(16)
December 31, 2015 Balance	$ 5	$ (11)	$ (6)

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, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (6)	Model	RTO auction clearing prices	($3.90) to $5.70	$0.70	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 and AFS securities.

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 NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset in net regulatory assets.

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, 2015 and December 31, 2014:

	December 31, 2015[1]			December 31, 2014[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$ 1,778	$ 16	$ 1,794	$ 1,724	$ 27	$ 1,751
FES	801	9	810	788	13	801
Equity securities						
FirstEnergy	$ 542	$ 34	$ 576	$ 533	$ 58	$ 591
FES	354	24	378	329	31	360

(1) Excludes short-term cash investments: FE Consolidated - $157 million; FES - $139 million.
(2) Excludes short-term cash investments: FE Consolidated - $241 million; FES - $204 million.

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, 2015, 2014 and 2013 were as follows:

December 31, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 1,534	$ 209	$ (191)	$ (102)	$ 101
FES	733	158	(134)	(90)	57

December 31, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 2,133	$ 146	$ (75)	$ (37)	$ 96
FES	1,163	113	(54)	(33)	56

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

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, 2015 and December 31, 2014:

	December 31, 2015			December 31, 2014		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$ 6	$ 2	$ 8	$ 13	$ 4	$ 17

The held-to-maturity debt securities contractually mature by June 30, 2017. Investments in employee benefit trusts and equity method investments totaling $255 million as of December 31, 2015 and $626 million as of December 31, 2014, 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, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$ 20,244	$ 21,519	$ 19,828	$ 21,733
FES	3,027	3,121	3,097	3,241

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, 2015 and December 31, 2014.

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 related 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) as follows:

- Changes in the fair value of derivative instruments that are designated and qualify as cash flow hedges are recorded to AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.
- Changes in the fair value of derivative instruments that are designated and qualify as fair value hedges are recorded as an adjustment to the item being hedged. When fair value hedges are discontinued, the adjustment recorded to the item being hedged is amortized into earnings.
- Changes in the fair value of derivative instruments that are not designated in a hedging relationship are recorded in earnings on a mark-to-market basis, unless otherwise noted.

Derivative instruments meeting the normal purchases and normal sales criteria are accounted for under the accrual method of accounting with their effects included in earnings at the time of contract performance.

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.

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $11 million and $8 million as of December 31, 2015 and December 31, 2014, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $1 million of net unamortized losses is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting interest rate 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 designated 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 pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $42 million and $50 million as of December 31, 2015 and December 31, 2014, respectively. Based on current estimates, approximately $9 million of these unamortized losses is expected to be amortized to interest expense during the next twelve months.

Refer to Note 2, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the years ended December 31, 2015 and 2014.

As of December 31, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as cash flow hedges.

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. As of December 31, 2015 and December 31, 2014, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $20 million and $32 million as of December 31, 2015 and December 31, 2014, respectively. During the next twelve months, approximately $10 million of unamortized gains is expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $12 million during the years ended December 31, 2015 and 2014.

As of December 31, 2015 and December 31, 2014, 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, 2015, FirstEnergy's net asset position under commodity derivative contracts was $97 million, which related to FES positions. Under these commodity derivative contracts, FES posted $26 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $3 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on derivative contracts held as of December 31, 2015, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next twelve months.

Interest Rate Swaps

As of December 31, 2015 and 2014, no interest rate swaps were outstanding.

NUGs

As of December 31, 2015, FirstEnergy's net liability position under NUG contracts was $136 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.

FTRs

As of December 31, 2015, FirstEnergy's and FES' net liability position under FTRs was $5 million and $6 million, respectively and FES posted $6 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 PJM. PJM 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 PJM, 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			Fair Value	
	December 31, 2015	December 31, 2014		December 31, 2015	December 31, 2014
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 150	$ 121	Commodity Contracts	$ (94)	$ (154)
FTRs	7	38	FTRs	(12)	(13)
	157	159		(106)	(167)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs[1]	(137)	(153)
			Noncurrent Liabilities - Other		
Commodity Contracts	78	51			
FTRs	1	1	Commodity Contracts	(37)	(13)
NUGs[1]	1	2	FTRs	(1)	(1)
	80	54		(175)	(167)
Derivative Assets	$ 237	$ 213	**Derivative Liabilities**	$ (281)	$ (334)

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

FirstEnergy enters into contracts with counterparties that allow for the offsetting of derivative assets and derivative liabilities under netting arrangements with the same counterparty. 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 assets and derivative liabilities on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

December 31, 2015	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 228	$ (125)	$ —	$ 103
FTRs	8	(8)	—	—
NUG contracts	1	—	—	1
	$ 237	$ (133)	$ —	$ 104
Derivative Liabilities				
Commodity contracts	$ (131)	$ 125	$ 3	$ (3)
FTRs	(13)	8	5	—
NUG contracts	(137)	—	—	(137)
	$ (281)	$ 133	$ 8	$ (140)

December 31, 2014	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 172	$ (126)	$ —	$ 46
FTRs	39	(14)	—	25
NUG contracts	2	—	—	2
	$ 213	$ (140)	$ —	$ 73
Derivative Liabilities				
Commodity contracts	$ (167)	$ 126	$ 35	$ (6)
FTRs	(14)	14	—	—
NUG contracts	(153)	—	—	(153)
	$ (334)	$ 140	$ 35	$ (159)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of December 31, 2015:

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	16	49	(33)	MWH
FTRs	29	—	29	MWH
NUGs	4	—	4	MWH
Natural Gas	83	—	83	mmBTU

The effect of active derivative instruments not in a hedging relationship on the Consolidated Statements of Income during 2015 and 2014 are summarized in the following tables:

	Year Ended December 31,		
	Commodity Contracts	FTRs	Total
	(In millions)		
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[1]	$ 93	$ (20)	$ 73
Realized Gain (Loss) Reclassified to:			
Revenues[2]	$ 111	$ 50	$ 161
Purchased Power Expense[3]	(130)	—	(130)
Other Operating Expense[4]	—	(49)	(49)
Fuel Expense	(34)	—	(34)

[1] Includes $93 million for commodity contracts and ($19) million for FTRs associated with FES.

[2] Includes $111 million for commodity contracts and $49 million for FTRs associated with FES.

[3] Includes ($130) million for commodity contracts associated with FES.

[4] Includes ($49) million for FTRs associated with FES.

	Year Ended December 31,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[5]	$ (86)	$ 22	$ —	$ (64)
Realized Gain (Loss) Reclassified to:				
Revenues[6]	$ (6)	$ 68	$ —	$ 62
Purchased Power Expense[7]	365	—	—	365
Other Operating Expense[8]	—	(44)	—	(44)
Fuel Expense	(6)	—	—	(6)
Interest Expense	—	—	14	14

[5] Includes ($86) million for commodity contracts and $21 million for FTRs associated with FES.

[6] Includes ($6) million for commodity contracts and $67 million for FTRs associated with FES.

[7] Realized losses on financially settled wholesale sales contracts of $252 million resulting from higher market prices were netted in purchased power. Includes $365 million for commodity contracts associated with FES.

[8] Includes ($43) million for FTRs associated with FES.

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during 2015 and 2014. Changes in the value of these contracts are deferred for future recovery from (or credit to) customers:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Year Ended December 31, NUGs	Regulated FTRs	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2015	$ (151)	$ 11	$ (140)
Unrealized loss	(47)	(9)	(56)
Purchases	—	12	12
Settlements	62	(13)	49
Outstanding net asset (liability) as of December 31, 2015	$ (136)	$ 1	$ (135)
Outstanding net liability as of January 1, 2014	$ (202)	$ —	$ (202)
Unrealized gain (loss)	(1)	13	12
Purchases	—	11	11
Settlements	52	(13)	39
Outstanding net asset (liability) as of December 31, 2014	$ (151)	$ 11	$ (140)

11. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2015, FirstEnergy's unrestricted retained earnings were $2.3 billion. Dividends declared in 2015 and 2014 were $1.44 per share, which included dividends of $0.36 per share paid in the first, second, third and fourth quarters. 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 19, 2016 the Board of Directors declared a quarterly dividend of $0.36 per share to be paid in the first quarter of 2016.

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 their respective parents from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 45%. 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, 2015.

Stock Issuance

In each of 2015 and 2014, FE issued approximately 2.5 million shares of common stock to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan and certain share-based benefit plans.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2015, as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$ 100		
OE	6,000,000	$ 100	8,000,000	no par
OE	8,000,000	$ 25		
Penn	1,200,000	$ 100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$ 100	5,000,000	$ 25
TE	12,000,000	$ 25		
JCP&L	15,600,000	no par		
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, 2015, and 2014, 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, 2015 and 2014:

	As of December 31, 2015		As of December 31	
(Dollar amounts in millions)	**Maturity Date**	**Interest Rate**	**2015**	**2014**
FirstEnergy:				
FMBs	2016 - 2045	3.340% - 9.740%	$ 3,269	$ 3,190
Secured notes - fixed rate	2016 - 2037	0.679% - 12.000%	2,096	2,247
Secured notes - variable rate	2017 - 2017	3.500% - 3.500%	2	—
Total secured notes			2,098	2,247
Unsecured notes - fixed rate	2016 - 2045	2.150% - 7.700%	13,580	13,078
Unsecured notes - variable rate	2017 - 2020	0.010% - 2.180%	1,292	1,292
Total unsecured notes			14,872	14,370
Capital lease obligations			132	160
Unamortized debt discounts			(18)	(8)
Unamortized fair value adjustments			5	21
Currently payable long-term debt			(1,166)	(804)
Total long-term debt and other long-term obligations			$ 19,192	$ 19,176
FES:				
Secured notes - fixed rate	2016 - 2018	5.625% - 12.000%	$ 340	$ 437
Secured notes - variable rate	2017 - 2017	3.500% - 3.500%	2	—
Total secured notes			342	437
Unsecured notes - fixed rate	2016 - 2039	2.150% - 6.800%	2,593	2,568
Unsecured notes - variable rate	2017 - 2017	0.010% - 0.010%	92	92
Total unsecured notes			2,685	2,660
Capital lease obligations			13	18
Unamortized debt discounts			(1)	(1)
Currently payable long-term debt			(512)	(506)
Total long-term debt and other long-term obligations			$ 2,527	$ 2,608

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

In August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L's short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also, in the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

In October 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, in October 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used: (i) to

fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

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. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. As of December 31, 2015 and 2014, $429 million and $450 million of environmental control bonds were outstanding, respectively.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include transition bonds issued by JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. The proceeds were used to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. As of December 31, 2015 and 2014, $128 million and $168 million of the transition bonds were outstanding, respectively.

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 to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. As of December 31, 2015 and 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.

See Note 8, Variable Interest Entities for additional information on securitized bonds.

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, 2015, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments of $3 million in 2015, all of which relate to Penn. Penn expects to meet its 2016 annual sinking fund requirement with a replacement credit under its mortgage indenture.

As of December 31, 2015, FirstEnergy's currently payable long-term debt included approximately $92 million of FES 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, 2015. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

Year	FirstEnergy	FES
	(In millions)	
2016	$ 1,039	$ 414
2017	1,733	257
2018	1,702	516
2019	2,268	322
2020	1,231	667

The following table classifies the outstanding fixed rate 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)	
2016	$ 391	$ 391
2017	222	222
2018	375	375
2019	232	232
2020	490	490

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 is entitled to a credit against its obligation to repay those bonds. FG pays annual fees based on the amounts of the LOCs to the issuing bank and is obligated to reimburse the bank for any drawings thereunder.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy and FES as of December 31, 2015, are as follows:

	Aggregate LOC Amount [1]	Annual Fees
	(In millions)	
FirstEnergy	$ 93	1.25%
FES	93	1.25%

(1) Includes approximately $1 million of applicable interest coverage.

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, 2015, 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 FE 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 FE. Also, defaults by FE would generally not cross-default applicable financing arrangements of any of FE's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FE, FG, NG or the Utilities.

12. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$ 3,500	$ 1,595
FES / AE Supply	Revolving	March 2019	1,500	1,442
FET[2]	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 4,037
		Cash	—	63
		Total	$ 6,000	$ 4,100

(1) FE and the Utilities
(2) Includes FET, ATSI and TrAIL as subsidiary borrowers

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) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

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, 2015:

Borrower	Revolving Credit Facility Sub-Limits	Regulatory and Other Short-Term Debt Limitations	
	(In millions)		
FE	$ 3,500	$ —	(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	500	(3)
ME	300	500	(3)
PN	300	300	(3)
WP	200	200	(3)
MP	500	500	(3)
PE	150	150	(3)
ATSI	500	500	(3)
Penn	50	100	(3)
TrAIL	400	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, $600 million of the FE 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.

As of December 31, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants under the respective Facilities.

Term Loans

FE has a $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan with a maturity date of May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2015, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants under each of these term loans.

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 2015 was 0.84% per annum for the regulated companies' money pool and 1.64% 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, 2015 and 2014, were as follows:

	2015	2014
FirstEnergy	2.16%	1.96%
FES	—%	3.34%

13. 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, 2015 and 2014 were as follows:

	2015	2014
	(In millions)	
FirstEnergy	$ 2,282	$ 2,341
FES	$ 1,327	$ 1,365

The following table summarizes the changes to the ARO balances during 2015 and 2014:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2014	$ 1,678	$ 1,015
Liabilities settled	(9)	(7)
Accretion	113	66
Revisions in estimated cash flows	(395)	(233)
Balance, December 31, 2014	$ 1,387	$ 841
Liabilities settled	(13)	(8)
Accretion	92	55
Revisions in estimated cash flows	(56)	(57)
Balance, December 31, 2015	$ 1,410	$ 831

During 2015, FE and FES reduced its ARO by $57 million based on the results of decommissioning cost studies for the Davis-Besse and Perry nuclear generating stations.

During 2014, based on studies by a third-party to reassess the estimated costs of decommissioning certain nuclear generating facilities, FE decreased its ARO by $395 million ($233 million at FES) of which $133 million was credited against a regulatory asset associated with nuclear decommissioning and spent fuel disposal costs for TMI-2. The decrease in the ARO primarily resulted from an extension in the number of years in which decommissioning activities are estimated to occur at Davis-Besse, Perry, TMI-2 and Beaver Valley Units 1 and 2.

14. 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 any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

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 SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. 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. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses 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 required 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's responsive filings 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 require 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. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

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 is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and 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 March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel's Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior 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);
- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;

- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations 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 FERC proceedings;
- 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, Ohio's renewable energy and energy efficiency standard, 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.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015. The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;
- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak

demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR 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. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

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, which is still pending. The matter has not been scheduled for oral argument.

Ohio law 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 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. 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. 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 certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, 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 spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies'

reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015, and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and

recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

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, NG, 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 occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an occurrence to RFC. Moreover, it is clear that 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 electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, 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 advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent “right of first refusal” to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM’s RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

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. While many of the matters involved with the move have been resolved, FERC denied recovery under 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 demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, 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. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for 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 before FERC and certain United States appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. 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. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC's prior ruling rejecting MISO's proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings. FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

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 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. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC's November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a 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 and other parties filed motions to dismiss, which FERC granted. The California Attorney General 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.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC’s ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the “zone of reasonableness” that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

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.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and 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. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in “underfunding” of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

15. 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 $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 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 (NG-$501 million) per incident but not more than $76 million (NG-$75 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 annually, corresponding to their respective nuclear

interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) 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 $15 million (NG-$15 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 $83 million (NG-$81 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, 2015, outstanding guarantees and other assurances aggregated approximately $3.7 billion, consisting of parental guarantees ($583 million), subsidiaries' guarantees ($2,137 million), other guarantees ($300 million) and other assurances ($667 million).

Of this aggregate amount, substantially all relates to guarantees of wholly-owned consolidated entities of FirstEnergy. 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, 2015, FES has posted collateral of $188 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 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, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 198	$ 6	$ 41	$ 245
BB+/Ba1 Credit Ratings	$ 231	$ 6	$ 41	$ 278
Full impact of credit contingent contractual obligations	$ 363	$ 16	$ 41	$ 420

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2015, 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 would be required to post $8 million with affiliated parties.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. 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 facility.

In connection with Global Holding's term loan facility, a portion of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with each of FEV's and WMB Marketing Ventures,LLC's 33-1/3% membership interests in Global Holding, are pledged to the lenders under Global Holding's facility as collateral. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FirstEnergy to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 8, Variable Interest Entities, and Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

ENVIRONMENTAL MATTERS

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

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission 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.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), 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. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel 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 plants. 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 plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. 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. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

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. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued 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. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become 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.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

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 the appeal or estimate the possible loss or range of loss.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal 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 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility.

FirstEnergy or its subsidiaries 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 Sheets as of December 31, 2015 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 $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 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 loss 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, 2015, FirstEnergy had approximately $2.3 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 NDTs 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 NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC’s Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

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 FirstEnergy's nuclear facilities.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The 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 14, 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.

16. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, interest on affiliated company notes including the money pools and other transactions.

FirstEnergy's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements. The primary affiliated company transactions for FES during the three years ended December 31, 2015 are as follows:

FES	2015	2014	2013
		(In millions)	
Revenues:			
Electric sales to affiliates	$ 664	$ 861	$ 652
Other	6	6	6
Expenses:			
Purchased power from affiliates	353	271	486
Fuel	1	1	—
Support services	705	619	619
Investment Income:			
Interest income from FE	2	3	2
Interest Expense:			
Interest expense to affiliates	4	3	4
Interest expense to FE	3	4	6

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions are generally settled under commercial terms within thirty days. 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.

FES and the Utilities are parties 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 are generally 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 (see Note 5, Taxes).

17. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the years ended December 31, 2015, 2014, and 2013, Condensed Consolidating Balance Sheets as of December 31, 2015 and December 31, 2014, and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2015, 2014, and 2013, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,824	$ 1,801	$ 2,138	$ (3,758)	$ 5,005
OPERATING EXPENSES:					
Fuel	—	679	192	—	871
Purchased power from affiliates	3,826	—	285	(3,758)	353
Purchased power from non-affiliates	1,684	—	—	—	1,684
Other operating expenses	399	275	618	49	1,341
Pension and OPEB mark-to-market adjustment	(8)	10	55	—	57
Provision for depreciation	12	124	191	(3)	324
General taxes	45	26	27	—	98
Total operating expenses	5,958	1,114	1,368	(3,712)	4,728
OPERATING INCOME (LOSS)	(1,134)	687	770	(46)	277
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	844	17	(5)	(870)	(14)
Miscellaneous income	1	2	—	—	3
Interest expense — affiliates	(29)	(8)	(4)	34	(7)
Interest expense — other	(52)	(104)	(49)	58	(147)
Capitalized interest	—	6	29	—	35
Total other income (expense)	764	(87)	(29)	(778)	(130)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(370)	600	741	(824)	147
INCOME TAXES (BENEFITS)	(452)	224	278	15	65
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	(9)	—	(8)	8	(9)
Other comprehensive loss	(18)	(5)	(8)	13	(18)
Income tax benefits on other comprehensive loss	(7)	(2)	(3)	5	(7)
Other comprehensive loss, net of tax	(11)	(3)	(5)	8	(11)
COMPREHENSIVE INCOME	$ 71	$ 373	$ 458	$ (831)	$ 71

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME (LOSS)					
REVENUES	$ 5,990	$ 1,902	$ 2,172	$ (3,920)	$ 6,144
OPERATING EXPENSES:					
Fuel	—	1,055	198	—	1,253
Purchased power from affiliates	3,920	—	271	(3,920)	271
Purchased power from non-affiliates	2,767	4	—	—	2,771
Other operating expenses	790	269	527	49	1,635
Pension and OPEB mark-to-market adjustment	19	90	188	—	297
Provision for depreciation	10	119	193	(3)	319
General taxes	72	31	25	—	128
Total operating expenses	7,578	1,568	1,402	(3,874)	6,674
OPERATING INCOME (LOSS)	(1,588)	334	770	(46)	(530)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(3)	(1)	(2)	—	(6)
Investment income, including net income from equity investees	791	8	61	(799)	61
Miscellaneous income	2	4	—	—	6
Interest expense — affiliates	(12)	(6)	(4)	15	(7)
Interest expense — other	(53)	(101)	(52)	60	(146)
Capitalized interest	—	4	30	—	34
Total other income (expense)	725	(92)	33	(724)	(58)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(863)	242	803	(770)	(588)
INCOME TAXES (BENEFITS)	(619)	87	298	6	(228)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(244)	155	505	(776)	(360)
Discontinued operations (net of income taxes of $70)	—	116	—	—	116
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(10)	—	—	—	(10)
Change in unrealized gain on available-for-sale securities	21	—	21	(21)	21
Other comprehensive income (loss)	5	(5)	21	(16)	5
Income taxes (benefits) on other comprehensive income (loss)	2	(2)	8	(6)	2
Other comprehensive income (loss), net of tax	3	(3)	13	(10)	3
COMPREHENSIVE INCOME (LOSS)	$ (241)	$ 268	$ 518	$ (786)	$ (241)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 6,068	$ 2,399	$ 1,634	$ (3,928)	$ 6,173
OPERATING EXPENSES:					
Fuel	—	1,056	206	—	1,262
Purchased power from affiliates	4,148	—	266	(3,928)	486
Purchased power from non-affiliates	2,326	7	—	—	2,333
Other operating expenses	635	275	529	48	1,487
Pension and OPEB mark-to-market adjustment	(8)	(37)	(36)	—	(81)
Provision for depreciation	6	127	178	(5)	306
General taxes	80	34	24	—	138
Total operating expenses	7,187	1,462	1,167	(3,885)	5,931
OPERATING INCOME (LOSS)	(1,119)	937	467	(43)	242
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income, including net income from equity investees	847	1	25	(857)	16
Miscellaneous income	4	24	—	—	28
Interest expense — affiliates	(13)	(5)	(6)	14	(10)
Interest expense — other	(63)	(104)	(54)	61	(160)
Capitalized interest	1	2	36	—	39
Total other income (expense)	673	(82)	1	(782)	(190)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(446)	855	468	(825)	52
INCOME TAXES (BENEFITS)	(506)	365	135	12	6
INCOME FROM CONTINUING OPERATIONS	60	490	333	(837)	46
Discontinued operations (net of income taxes of $8)	—	14	—	—	14
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(15)	(13)	—	13	(15)
Amortized gain on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available-for-sale securities	(8)	—	(8)	8	(8)
Other comprehensive loss	(29)	(13)	(8)	21	(29)
Income tax benefits on other comprehensive loss	(11)	(5)	(3)	8	(11)
Other comprehensive loss, net of tax	(18)	(8)	(5)	13	(18)
COMPREHENSIVE INCOME	$ 42	$ 496	$ 328	$ (824)	$ 42

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	275	—	—	—	275
Affiliated companies	433	403	461	(846)	451
Other	36	4	19	—	59
Notes receivable from affiliated companies	406	1,210	805	(2,410)	11
Materials and supplies	53	204	213	—	470
Derivatives	154	—	—	—	154
Collateral	70	—	—	—	70
Prepayments and other	48	18	—	—	66
	1,475	1,841	1,498	(3,256)	1,558
PROPERTY, PLANT AND EQUIPMENT:					
In service	93	6,367	8,233	(382)	14,311
Less — Accumulated provision for depreciation	40	2,144	3,775	(194)	5,765
	53	4,223	4,458	(188)	8,546
Construction work in progress	30	249	878	—	1,157
	83	4,472	5,336	(188)	9,703
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,327	—	1,327
Investment in affiliated companies	7,452	—	—	(7,452)	—
Other	—	10	—	—	10
	7,452	10	1,327	(7,452)	1,337
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	300	16	—	(316)	—
Customer intangibles	61	—	—	—	61
Goodwill	23	—	—	—	23
Property taxes	—	12	28	—	40
Derivatives	79	—	—	—	79
Other	33	318	21	12	384
	496	346	49	(304)	587
	$ 9,506	$ 6,669	$ 8,210	$ (11,200)	$ 13,185
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ —	$ 229	$ 308	$ (25)	$ 512
Short-term borrowings-					
Affiliated companies	2,021	389	—	(2,410)	—
Other	—	8	—	—	8
Accounts payable-					
Affiliated companies	884	146	368	(856)	542
Other	21	118	—	—	139
Accrued taxes	7	93	62	(86)	76
Derivatives	103	1	—	—	104
Other	66	61	9	45	181
	3,102	1,045	747	(3,332)	1,562
CAPITALIZATION:					
Total equity	5,605	2,944	4,476	(7,420)	5,605
Long-term debt and other long-term obligations	694	2,122	847	(1,136)	2,527
	6,299	5,066	5,323	(8,556)	8,132
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	791	791
Accumulated deferred income taxes	6	—	697	(103)	600
Asset retirement obligations	—	191	640	—	831
Retirement benefits	27	305	—	—	332
Derivatives	37	1	—	—	38
Other	35	61	803	—	899
	105	558	2,140	688	3,491
	$ 9,506	$ 6,669	$ 8,210	$ (11,200)	$ 13,185

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	415	—	—	—	415
Affiliated companies	484	487	674	(1,120)	525
Other	66	21	20	—	107
Notes receivable from affiliated companies	339	838	272	(1,449)	—
Materials and supplies	67	202	223	—	492
Derivatives	147	—	—	—	147
Collateral	229	—	—	—	229
Prepayments and other	48	19	—	1	68
	1,795	1,569	1,189	(2,568)	1,985
PROPERTY, PLANT AND EQUIPMENT:					
In service	133	6,217	7,628	(382)	13,596
Less — Accumulated provision for depreciation	36	2,058	3,305	(191)	5,208
	97	4,159	4,323	(191)	8,388
Construction work in progress	3	206	801	—	1,010
	100	4,365	5,124	(191)	9,398
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,365	—	1,365
Investment in affiliated companies	6,607	—	—	(6,607)	—
Other	—	10	—	—	10
	6,607	10	1,365	(6,607)	1,375
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	284	98	—	(382)	—
Customer intangibles	78	—	—	—	78
Goodwill	23	—	—	—	23
Property taxes	—	14	27	—	41
Unamortized sale and leaseback costs	—	—	—	—	—
Derivatives	52	—	—	—	52
Other	34	277	7	13	331
	471	389	34	(369)	525
	$ 8,973	$ 6,333	$ 7,712	$ (9,735)	$ 13,283
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 18	$ 164	$ 348	$ (24)	$ 506
Short-term borrowings-					
Affiliated companies	1,135	321	28	(1,449)	35
Other	90	9	—	—	99
Accounts payable-					
Affiliated companies	1,068	197	219	(1,068)	416
Other	46	202	—	—	248
Accrued taxes	2	62	161	(123)	102
Derivatives	166	—	—	—	166
Other	72	56	9	47	184
	2,597	1,011	765	(2,617)	1,756
CAPITALIZATION:					
Total equity	5,585	2,561	4,014	(6,575)	5,585
Long-term debt and other long-term obligations	695	2,215	859	(1,161)	2,608
	6,280	4,776	4,873	(7,736)	8,193
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	824	824
Accumulated deferred income taxes	13	—	678	(207)	484
Asset retirement obligations	—	189	652	—	841
Retirement benefits	36	288	—	—	324
Derivatives	14	—	—	—	14
Other	33	69	744	1	847
	96	546	2,074	618	3,334
	$ 8,973	$ 6,333	$ 7,712	$ (9,735)	$ 13,283

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (637)	$ 551	$ 1,261	$ (24)	$ 1,151
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	45	296	—	341
Short-term borrowings, net	796	67	—	(863)	—
Redemptions and Repayments-					
Long-term debt	(17)	(70)	(348)	24	(411)
Short-term borrowings, net	—	—	(28)	(98)	(126)
Common stock dividend payment	(70)	—	—	—	(70)
Other	—	(5)	(1)	—	(6)
Net cash provided from (used for) financing activities	709	37	(81)	(937)	(272)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(223)	(399)	—	(627)
Nuclear fuel	—	—	(190)	—	(190)
Proceeds from asset sales	10	3	—	—	13
Sales of investment securities held in trusts	—	—	733	—	733
Purchases of investment securities held in trusts	—	—	(791)	—	(791)
Cash Investments	(10)	—	—	—	(10)
Loans to affiliated companies, net	(67)	(372)	(533)	961	(11)
Other	—	4	—	—	4
Net cash used for investing activities	(72)	(588)	(1,180)	961	(879)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (600)	$ 408	$ 785	$ (22)	$ 571
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	431	447	—	878
Short-term borrowings, net	247	114	—	(361)	—
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	(1)	(269)	(568)	22	(816)
Short-term borrowings, net	—	—	(123)	(178)	(301)
Other	(1)	(12)	(2)	—	(15)
Net cash provided from (used for) financing activities	745	264	(246)	(517)	246
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8)	(169)	(662)	—	(839)
Nuclear fuel	—	—	(233)	—	(233)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	1,163	—	1,163
Purchases of investment securities held in trusts	—	—	(1,219)	—	(1,219)
Loans to affiliated companies, net	(136)	(815)	412	539	—
Other	(1)	5	—	—	4
Net cash used for investing activities	(145)	(672)	(539)	539	(817)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (1,429)	$ 753	$ 776	$ (22)	$ 78
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	864	371	150	(954)	431
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(770)	(364)	(90)	22	(1,202)
Short-term borrowings, net	(244)	(505)	—	749	—
Tender premiums	(67)	—	—	—	(67)
Other	(4)	(5)	—	—	(9)
Net cash provided from (used for) financing activities	1,279	(503)	60	(183)	653
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(12)	(256)	(449)	—	(717)
Nuclear fuel	—	—	(250)	—	(250)
Proceeds from asset sales	—	21	—	—	21
Sales of investment securities held in trusts	—	—	940	—	940
Purchases of investment securities held in trusts	—	—	(1,000)	—	(1,000)
Loans to affiliated companies, net	163	(15)	(77)	205	276
Other	(1)	(1)	—	—	(2)
Net cash provided from (used for) investing activities	150	(251)	(836)	205	(732)
Net change in cash and cash equivalents	—	(1)	—	—	(1)
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

18. SEGMENT INFORMATION

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission and CES.

Financial information for each of FirstEnergy's reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

During the fourth quarter of 2015, management concluded that FEV's 33-1/3% equity investment in Global Holding was no longer a strategic asset to CES. Because of this decision, the segment reporting was modified to reflect how management now views and makes investment decisions regarding CES and Global Holding. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2014 and 2013 have been reclassified to conform to the current presentation reflecting the activity of FEV's investment in Global Holding in Corporate/Other.

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 located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 3,790 MWs of generation capacity.

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). This segment also includes 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 primarily from transmission services provided pursuant to its PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The **CES** segment, through FES and AE Supply, primarily 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 13,162 MWs of capacity. The CES 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 and capacity costs charged by PJM to deliver energy to the segment's customers.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates and $1.7 billion was borrowed under the FE revolving credit facility.

Segment Financial Information

For the Years Ended December 31,	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate / Other	Reconciling Adjustments	Consolidated
			(In millions)			
2015						
External revenues	$ 9,625	$ 1,011	$ 4,698	$ (168)	$ (140)	$ 15,026
Internal revenues	—	—	686	—	(686)	—
Total revenues	9,625	1,011	5,384	(168)	(826)	15,026
Depreciation	672	156	394	60	—	1,282
Amortization of regulatory assets, net	261	7	—	—	—	268
Impairment of long-lived assets	8	—	34	—	—	42
Investment income (loss)	42	—	(16)	(9)	(39)	(22)
Impairment of equity method investment	—	—	—	362	—	362
Interest expense	586	161	192	193	—	1,132
Income taxes (benefits)	342	174	50	(262)	11	315
Income (loss) from continuing operations	618	298	89	(427)	—	578
Discontinued operations, net of tax	—	—	—	—	—	—
Net income (loss)	618	298	89	(427)	—	578
Total assets	27,876	7,439	16,365	507	—	52,187
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,108	952	588	56	—	2,704
2014						
External revenues	$ 9,102	$ 769	$ 5,470	$ (146)	$ (146)	$ 15,049
Internal revenues	—	—	819	—	(819)	—
Total revenues	9,102	769	6,289	(146)	(965)	15,049
Depreciation	658	127	387	48	—	1,220
Amortization of regulatory assets, net	1	11	—	—	—	12
Impairment of long-lived assets	—	—	—	—	—	—
Investment income (loss)	56	—	54	2	(40)	72
Impairment of equity method investment	—	—	—	—	—	—
Interest expense	589	131	189	168	(4)	1,073
Income taxes (benefits)	227	121	(223)	(178)	11	(42)
Income (loss) from continuing operations	465	223	(417)	(58)	—	213
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	465	223	(331)	(58)	—	299
Total assets	28,085	6,252	16,518	793	—	51,648
Total goodwill	5,092	526	800	—	—	6,418
Property additions	972	1,329	939	72	—	3,312
2013						
External revenues	$ 8,720	$ 731	$ 5,728	$ (121)	$ (166)	$ 14,892
Internal revenues	—	—	770	—	(770)	—
Total revenues	8,720	731	6,498	(121)	(936)	14,892
Depreciation	606	114	439	43	—	1,202
Amortization of regulatory assets, net	529	10	—	—	—	539
Impairment of long-lived assets	322	—	473	—	—	795
Investment income (loss)	57	—	14	6	(44)	33
Impairment of equity method investment	—	—	—	—	—	—
Interest expense	543	93	222	148	10	1,016
Income taxes (benefits)	301	129	(140)	(105)	10	195
Income (loss) from continuing operations	501	214	(235)	(105)	—	375
Discontinued operations, net of tax	—	—	17	—	—	17
Net income (loss)	501	214	(218)	(105)	—	392
Total assets	27,683	5,247	16,782	712	—	50,424
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,272	461	827	78	—	2,638

19. DISCONTINUED OPERATIONS

On February 12, 2014, certain of FirstEnergy's subsidiaries sold eleven hydroelectric power stations to a subsidiary of LS Power for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million). Pre-tax income for the hydroelectric facilities of $155 million and $26 million (FES - $186 million and $22 million) for the years ended December 31, 2014 and 2013, respectively, was included in discontinued operations in the Consolidated Statement of Income. Included in income for discontinued operations in the year ended December 31, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million and $33 million (FES - $5 million and $31 million) for years ended December 31, 2014 and 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income.

20. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2015 and 2014.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	2015				2014			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	$ 3,541	$ 4,123	$ 3,465	$ 3,897	$ 3,483	$ 3,888	$ 3,496	$ 4,182
Other operating expense	952	850	916	1,057	901	858	1,021	1,182
Pension and OPEB mark-to-market adjustment	242	—	—	—	835	—	—	—
Provision for depreciation	313	328	322	319	316	308	302	294
Operating Income (Loss)	236	908	554	594	(337)	716	292	391
Income (loss) from continuing operations before income taxes (benefits)	(396)	621	302	366	(574)	485	90	170
Income taxes (benefits) [1]	(170)	226	115	144	(268)	152	26	48
Income (loss) from continuing operations	(226)	395	187	222	(306)	333	64	122
Discontinued operations (net of income taxes)	—	—	—	—	—	—	—	86
Net Income (Loss)	(226)	395	187	222	(306)	333	64	208
Earnings (loss) per share of common stock-[2]								
Basic - Continuing Operations	(0.53)	0.94	0.44	0.53	(0.73)	0.79	0.16	0.29
Basic - Discontinued Operations (Note 19)	—	—	—	—	—	—	—	0.21
Basic - Earnings Available to FirstEnergy Corp.	(0.53)	0.94	0.44	0.53	(0.73)	0.79	0.16	0.50
Diluted - Continuing Operations	(0.53)	0.93	0.44	0.53	(0.73)	0.79	0.15	0.29
Diluted - Discontinued Operations (Note 19)	—	—	—	—	—	—	—	0.20
Diluted - Earnings Available to FirstEnergy Corp.	(0.53)	0.93	0.44	0.53	(0.73)	0.79	0.15	0.49

[1] During the fourth quarter of 2014, income tax benefits of $16 million were recorded that related to prior periods. The out-of-period adjustment primarily related to the correction of amounts included in the Company's tax basis balance sheet. Management determined that this adjustment was not material to 2014 or any prior period.

[2] Total quarterly earnings per share information may not equal annual earnings per share due to the issuance of shares throughout the year. See FirstEnergy's Consolidated Statements of Stockholders' Equity and Note 4. Stock-Based Compensation for additional information.

FES

CONSOLIDATED STATEMENTS OF INCOME

(In millions)	2015				2014			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	$ 1,171	$ 1,338	$ 1,119	$ 1,377	$ 1,342	$ 1,521	$ 1,452	$ 1,829
Other operating expense	329	246	353	413	359	356	468	452
Pension and OPEB mark-to-market adjustment	57	—	—	—	297	—	—	—
Provision for depreciation	84	79	81	80	83	83	79	74
Operating Income (Loss)	25	240	—	12	(321)	90	(151)	(148)
Income (loss) from continuing operations before income taxes (benefits)	(13)	190	(25)	(5)	(347)	72	(154)	(159)
Income taxes (benefits)	1	70	(4)	(2)	(133)	28	(67)	(56)
Income (loss) from continuing operations	(14)	120	(21)	(3)	(214)	44	(87)	(103)
Discontinued operations (net of income taxes)	—	—	—	—	—	—	—	116
Net Income (Loss)	(14)	120	(21)	(3)	(214)	44	(87)	13

Executive Officers as of February 16, 2016

Name	Age	Positions Held During Past Five Years	Dates
G. D. Benz	56	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	2012-2015
L. M. Cavalier	64	Chief Human Resources Officer (B)	2015-present
		Senior Vice President, Human Resources (B)	*-2015
D. M. Chack	65	Senior Vice President, Marketing and Branding (B)	2015-present
		President, Ohio Operations (B)	2011-2015
		Vice President (C)	2011-2015
		Regional President (M)	*-2011
M. J. Dowling	51	Senior Vice President, External Affairs (B)	2011-present
		Vice President, External Affairs (B)	*-2011
B. L. Gaines	62	Senior Vice President, Corporate Services and Chief Information Officer (B)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)	2011-2012
		Vice President, Shared Services, Administration and Chief Information Officer (B)	*-2011
C. E. Jones	60	President and Chief Executive Officer (A)(B)	2015-present
		Chief Executive Officer (F)	2015-present
		Executive Vice President & President, FirstEnergy Utilities (A)(B)	2014
		Senior Vice President & President, FirstEnergy Utilities (B)	*-2013
		President (H)(I)	2011-2015
		President (C)(D)(L)	*-2015
		Senior Vice President & President, FirstEnergy Utilities (A)	*-2011
J. H. Lash	65	Executive Vice President & President, FE Generation (A)(B)	2015-present
		President, FE Generation (B)	2011-2015
		President (G)(J)	2011-present
		Chief Nuclear Officer (F)	2011-2012
		President and Chief Nuclear Officer (F)	*-2011
		President, FirstEnergy Nuclear Operating Company (B)	*-2011
C. D. Lasky	53	Senior Vice President, Human Resources (B)	2015-present
		Vice President, Fossil Operations (J)	2014-2015
		Vice President, Fossil Operations & Engineering (J)	2014
		Vice President (G)	2011-2015
		Vice President, Fossil Fleet Operations (J)	2011-2013
		Vice President (J)	*-2011
		Vice President, Fossil Operations (E)	*-2011
J. F. Pearson	61	Executive Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2015-present
		Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-2015
		Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012
		Vice President and Treasurer (A)(B)(C)(D)(E)(F)(J)(L)	*-2012
		Vice President and Treasurer (G)(H)(I)	2011-2012
D. R. Schneider	54	President (E)	*-present
S. E. Strah	52	Senior Vice President & President, FirstEnergy Utilities (B)	2015-present
		President (C)(D)(H)(I)(L)	2015-present
		Vice President, Distribution Support (B)	2011-2015
		Regional President (K)	*-2011
K. J. Taylor	42	Vice President, Controller and Chief Accounting Officer (A)(B)	2013-present
		Vice President and Controller (C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-present
		Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012-2013
		Assistant Controller (A)(B)(C)(D)(L)	*-2012
		Assistant Controller (H)(I)	2011-2012
		Assistant Controller (E)(F)(G)(J)	2012
L. L. Vespoli	56	Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2014-present
		Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(J)(L)	*-2013
		Executive Vice President and General Counsel (G)(H)(I)	2011-2013

* Indicates position held at least since January 1, 2011
(A) Denotes executive officer of FE
(B) Denotes executive officer of FESC
(C) Denotes executive officer of OE, CEI and TE
(D) Denotes executive officer of ME, PN and Penn
(E) Denotes executive officer of FES
(F) Denotes executive officer of FENOC
(G) Denotes executive officer of AGC
(H) Denotes executive officer of MP, PE and WP
(I) Denotes executive officer of TrAIL and FET
(J) Denotes executive officer of FG
(K) Denotes executive officer of OE
(L) Denotes executive officer of ATSI
(M) Denotes executive officer of CEI

SHAREHOLDER SERVICES

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company, LLC (AST) is the company's Transfer Agent and Registrar. Registered shareholders wanting to transfer stock, or who need assistance or information, can send their stock certificate(s) or write to FirstEnergy Corp., c/o American Stock Transfer & Trust Company, LLC, P.O. Box 2016, New York, NY 10272-2016. Shareholders also can call toll-free at 1-800-736-3402, between 8:00 a.m. and 8:00 p.m. Eastern time, Monday through Friday. For Internet access to general shareholder and account information, visit the AST website at www.amstock.com/company/firstenergy.asp.

STOCK INVESTMENT PLAN

Registered shareholders and employees of the company can participate in the Stock Investment Plan. To learn more about the company's Stock Investment Plan, visit AST's website at www.amstock.com/company/firstenergy.asp or contact AST toll-free at 1-800-736-3402.

DIRECT DIVIDEND DEPOSIT

Registered shareholders can have their dividend payments automatically deposited to checking, savings or credit union accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact AST toll-free at 1-800-736-3402 to receive a Direct Dividend Deposit Authorization Agreement.

STOCK LISTING AND TRADING

The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

FORM 10-K ANNUAL REPORT

The Annual Report on Form 10-K, as filed with the Securities and Exchange Commission, including the financial statements and financial statement schedules, will be sent to you without charge upon written request to Rhonda S. Ferguson, Vice President and Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You also can view the Form 10-K by visiting the company's website at www.firstenergycorp.com/financialreports.

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