FIRSTENERGY CORP
Form 10-K
February 21, 2017

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

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

For the FISCAL YEAR ended December 31, 2016

OR

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

For the transition period from ____________________ to ____________________

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

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

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

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

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

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

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

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

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

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

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

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

þ FirstEnergy Corp.

þ FirstEnergy Solutions Corp.

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

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

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

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

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

FirstEnergy Corp., $14,809,049,520 as of June 30, 2016; and for FirstEnergy Solutions Corp., none.

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

CLASS	OUTSTANDING AS OF JANUARY 31, 2017
FirstEnergy Corp., $0.10 par value	442,477,633
FirstEnergy Solutions Corp., no par value	7

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

Documents Incorporated By Reference

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2017 Annual Meeting of Shareholders to be held May 16, 2017	Part III

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

Solutions Corp. is also attributed to FirstEnergy Corp.

OMISSION OF CERTAIN INFORMATION

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

Forward-Looking Statements: Certain of the matters discussed in this Annual Report on Form 10-K are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, including those factors with respect to such Registrants discussed in (a) Item 1A. Risk Factors, (b) 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 the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Form 10-K. Neither of the Registrants undertake any obligation to update these statements, except as required by law.

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GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011, 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., together with its consolidated subsidiaries, 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, MAIT 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 hydroelectric 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

GLOSSARY OF TERMS, Continued

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

AAA	American Arbitration Association
ADIT	Accumulated Deferred Income Taxes
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
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
Aspen	Aspen Generating, LLC, a wholly-owned subsidiary of LS Power Equity Partners III, LP
ASU	Accounting Standards Update
Bath County	Bath County Pumped Storage Hydro-Power Station
BGS	Basic Generation Service
bps	Basis points
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
DMR	Distribution Modernization Rider
DOE	United States Department of Energy
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
DTA	Deferred Tax Asset
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation

EGS	Electric Generation Supplier
EGU	Electric Generation Unit
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

GLOSSARY OF TERMS, Continued

EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERISA	Employee Retirement Income Security Act of 1974
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
ESP IV	Electric Security Plan IV
ESP IV PPA	Unit Power Agreement entered into on April 1, 2016 by and between the Ohio Companies and FES
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
IRP	Integrated Resource 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
LIBOR	London Interbank Offered Rate
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

GLOSSARY OF TERMS, Continued

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
NOAC	Northwest Ohio Aggregation Coalition
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
ORC	Ohio Revised Code
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	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run

GLOSSARY OF TERMS, Continued

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
SRC	Storm Recovery Charge
SREC	Solar Renewable Energy Credit
SSA	Social Security Administration
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
VEPCO	Virginia Electric Power Company
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

PART I
ITEM 1. BUSINESS
The Companies

FE 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 equity 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 equity of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and Allegheny Ventures, Inc.

FE and its subsidiaries are principally 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, based on serving six million customers in the Midwest and Mid-Atlantic regions. Its regulated and unregulated generation subsidiaries control nearly 17,000 MWs 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's revenues are primarily derived from the sale of energy and related products and services by its unregulated competitive subsidiaries (FES and AE Supply), electric service provided by its utility operating subsidiaries (OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE, and WP) and its transmission subsidiaries (ATSI and TrAIL).

Unregulated Competitive Subsidiaries

FES, a subsidiary of FE, was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to retail and wholesale customers. FES also owns and operates, through its FG subsidiary, fossil generating facilities and owns, through its NG subsidiary, nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and purchases 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. FG, as subsidiary of FES, was organized under the laws of the State of Ohio in 2000. FG sells the entire output of its fossil generating facilities (5,636 MWs) to FES. NG, as subsidiary of FES, was organized under the laws of the State of Ohio in 2005. NG sells the entire output of its nuclear generating facilities (4,048 MWs) to FES. NG's nuclear generating facilities are operated and maintained by FENOC, a separate subsidiary of FE, organized under the laws of the State of Ohio in 1998.

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

AGC was organized under the laws of the Commonwealth of Virginia in 1981. Approximately 59% of AGC is owned by AE Supply and approximately 41% by MP. AGC's sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility (1,200 MWs) and its connecting transmission facilities. AGC provides the generation capacity from this facility to AE Supply and MP.

On January 18, 2017, AE Supply and AGC entered into an asset purchase agreement with Aspen for the sale of 1,572 MWs of natural gas and hydroelectric assets, including AE Supply's indirect interest in Bath County. Under the terms of the agreement, the facilities would be purchased for an all cash purchase price of approximately $925 million. The transaction is expected to close in the third quarter of 2017 subject to satisfaction of various customary and other closing conditions, including, without limitation, receipt of regulatory approvals, third party consents and the satisfaction and discharge of AE Supply’s senior note indenture, under which there is approximately $305 million aggregate principal amount of indebtedness outstanding. There can be no assurance that any such approvals will be obtained and/or any such conditions will be satisfied or that such sale will be consummated. Further, the satisfaction and discharge of AE Supply’s senior note indenture in connection with the closing is expected to require the payment of a “make-whole” premium calculated just prior to the redemption, which based on current interest rates is approximately $100 million. It is expected that proceeds from the sale will be invested in the unregulated money pool and may be used for the repayment of debt and general corporate purposes.

As a further condition to closing, FE will provide Aspen two limited guaranties of certain obligations of AE Supply and AGC arising under the purchase agreement. The guaranties vary in amount and scope with expiration dates of one year and three years from the transaction close date.

Additionally, in connection with MP's RFP seeking additional capacity, AE Supply offered the Pleasants power station (1,300 MWs) for approximately $195 million.

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

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Utility Operating Subsidiaries

The Utilities' combined service areas encompass approximately 65,000 square miles in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. The areas they serve have a combined population of approximately 13.3 million.

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

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

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the distribution and sale of electric energy in an area of 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.6 million.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the distribution and sale of electric energy in an area of 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.7 million.

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has a 50% ownership interest (210 MWs) in a hydroelectric generating facility.

ME was organized under the laws of the Commonwealth of Pennsylvania in 1917 and owns property and does business as an electric public utility in that state. ME provides transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million. Additionally, as discussed in "FERC Matters" below, ME transferred its transmission assets to MAIT on January 31, 2017.

PN was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. PN provides transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million. PN, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in the Waverly, New York vicinity. Additionally, as discussed in "FERC Matters" below, PN transferred its transmission assets to MAIT on January 31, 2017.

PE was organized under the laws of the State of Maryland in 1923 and in the Commonwealth of Virginia in 1974. PE is authorized to do business in the Commonwealth of Virginia and the States of West Virginia and Maryland. PE owns property and does business as an electric public utility in those states. PE provides transmission and distribution services in portions of Maryland and West Virginia and provides transmission services in Virginia in an area totaling approximately 5,500 square miles. The area it serves has a population of approximately 0.9 million.

MP was organized under the laws of the State of Ohio in 1924 and owns property and does business as an electric public utility in the state of West Virginia. MP provides generation, transmission and distribution services in 13,000 square miles of northern West Virginia. The area it serves has a population of approximately 0.8 million. As of December 31, 2016, MP owned or contractually controlled 3,580 MWs of generation capacity that is supplied to its electric utility business. In addition, MP is contractually obligated to provide power to PE to meet its load obligations in West Virginia. Refer to "Regulated Generation" below for discussion of MP's RFPs to address its generation shortfall and to sell its interest in Bath County.

WP was organized under the laws of the Commonwealth of Pennsylvania in 1916 and owns property and does business as an electric public utility in that state. WP provides transmission and distribution services in 10,400 square miles of southwestern, south-central and northern Pennsylvania. The area it serves has a population of approximately 1.5 million.

The Utilities comply with the regulations, orders, policies and practices prescribed by the SEC, FERC, and their respective state regulatory authorities (PUCO, PPUC, NJBPU, WVPSC, MDPSC, and VSCC).

Transmission Subsidiaries

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns major, high-voltage transmission facilities, which consist of approximately 7,800 circuit miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV in the PJM Region.

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

MAIT was organized under the laws of the State of Delaware in 2015. As discussed in "FERC Matters" below, ME and PN transferred their transmission facilities to MAIT on January 31, 2017. The assets transferred consist of approximately 4,283 circuit miles of transmission lines with nominal voltages of 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, 69 kV and 46 kV in the PJM Region.

Each of ATSI, MAIT and TrAIL plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, each of ATSI, MAIT and TrAIL complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and applicable state regulatory authorities.

Service Company

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

Operating Segments

FirstEnergy's reportable operating 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 controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI and 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 forward-looking rates at ATSI and TrAIL, as well as stated transmission rates at certain of FirstEnergy's utilities. As discussed in "FERC Matters" below, effective January 31, 2017, MAIT includes the transmission assets of ME and PN, and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. Those applications are pending before FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under the forward-looking rates, each of ATSI's and TrAIL's revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. Except for the recovery of the PATH abandoned project regulatory asset, the segment's revenues are primarily from transmission services provided to LSEs pursuant to the PJM Tariff. 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. As of December 31, 2016, this business segment controlled 13,162 MWs of electric generating capacity, including, as discussed in "Unregulated Competitive Subsidiaries" above, 1,572 MWs of natural gas and hydroelectric generating capacity subject to an asset purchase agreement with Aspen and the 1,300 MW Pleasants power station which was offered into MP's RFP process by AE Supply. The CES segment’s operating results are 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, as well as other operating and maintenance costs, including costs incurred by FENOC.

Corporate support not charged to FE's subsidiaries, interest expense on stand-alone holding company debt, corporate income taxes and other businesses that do not constitute an operating segment 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, 2016, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $2.7 billion was borrowed by FE under its revolving credit facility.

Additional information regarding FirstEnergy’s reportable segments is provided in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Note 19, Segment Information", of the Combined Notes to Consolidated Financial Statements. FES does not have separate reportable operating segments.

Competitive Generation

As of February 21, 2017, FirstEnergy's competitive generating portfolio consists of 13,162 MWs of electric generating capacity. Of the generation asset portfolio, approximately 6,136 MWs (46.6%) consist of coal-fired capacity; 4,048 MWs (30.8%) consist of nuclear capacity; 713 MWs (5.4%) consist of hydroelectric capacity; 1,592 MWs (12.1%) consist of oil and natural gas units; 496 MWs (3.8%) consist of wind and solar power arrangements; and 177 MWs (1.3%) consist of capacity entitlements to output from generation assets owned by OVEC. All units are located within PJM and sell electric energy, capacity and other products into the wholesale markets that are operated by PJM. Within CES' generation portfolio, 10,180 MWs consist of FES' facilities that are operated by FENOC and FG (including entitlements from OVEC, wind and solar power arrangements), and except for portions of Bruce Mansfield and Beaver Valley Unit 2 facilities that are subject to the sale and leaseback arrangements with non-affiliates for which the corresponding output of these arrangements is available to FES through power sales agreements, are all owned directly by NG and FG. Another 2,982 MWs of the CES' portfolio consists of AE Supply's facilities, including AE Supply's entitlement to 713 MWs from AGC's interest in Bath County and 67 MWs of AE Supply's 3.01% entitlement from OVEC's generation output. As discussed below, AE Supply and AGC have agreed to sell to Aspen 1,572 MWs of electric generating capacity, and AE Supply offered its 1,300 MW Pleasants power station into MP's RFP process. FES' generating facilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's generating facilities are primarily located in Pennsylvania, West Virginia, Virginia and Ohio.

Over the past several years, CES has been impacted by a prolonged decrease in demand and excess generation supply in the PJM Region, which has resulted in a period of protracted low power and capacity prices. To address this, CES sold or deactivated more than 6,770 MWs of competitive generation from 2012 to 2015. Additionally, CES has continued to focus on cost reductions, including those identified as part of FirstEnergy's previously disclosed cash flow improvement plan.

However, the energy and capacity markets continue to be weak, as evidenced by the significantly depressed capacity prices from the 2019/2020 PJM Base Residual Auction in May of 2016, as well as the current forward pricing and the long term fundamental view on energy and capacity prices, which resulted in a non-cash pre-tax impairment charge of $800 million ($23 million at FES) recognized in the second quarter of 2016 representing the total amount of goodwill at CES.

As part of a continual process to evaluate its overall generation business, on July 22, 2016, FirstEnergy announced its intent to exit the 136 MW Bay Shore Unit 1 generating station by October 2020 and to deactivate Units 1-4 of the W.H. Sammis generating station totaling 720 MWs by May 2020, resulting in a $647 million ($517 million at FES) non-cash pre-tax impairment charge in the second quarter of 2016. Furthermore, in November of 2016, FirstEnergy announced that it had begun a strategic review of its competitive operations as it transitions to a fully regulated utility with a target to implement its exit from competitive operations by mid-2018.

As a result of this strategic review, as further discussed above, FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement to sell four of AE Supply's natural gas generating plants and approximately 59% of AGC's interest in Bath County (1,572 MWs of combined capacity) for an all cash purchase price of $925 million, subject to customary and other closing conditions and, in February 2017, in connection with MP's RFP seeking additional generation capacity, AE Supply offered the Pleasants power station (1,300 MWs) for approximately $195 million, which remains pending.

Although FirstEnergy is targeting mid-2018 to exit competitive operations, the options for the remaining portion of CES' generation are still uncertain, but could include one or more of the following:

- Legislative or regulatory solutions for generation assets that recognize their environmental or energy security benefits,
- Additional asset sales and/or plant deactivations,
- Restructuring FES debt with its creditors, and/or
- Seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

Furthermore, adverse outcomes in previously disclosed disputes regarding long-term coal transportation contracts and/or the inability to extend or refinance debt maturities at FES subsidiaries, could accelerate management's targeted timeline and limit its options to exit competitive operations to either restructuring debt with its creditors or seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

As part of assessing the viability of strategic alternatives, FirstEnergy determined that the carrying value of long-lived assets of the competitive business were not recoverable, specifically given FirstEnergy's target to implement its exit from competitive operations by mid-2018, significantly before the end of their original useful lives, and the anticipated cash flows over this shortened period. As a result, CES recorded a non-cash pre-tax impairment charge of $9,218 million ($8,082 million at FES) in the fourth quarter of 2016 to reduce the carrying value of certain assets to their estimated fair value, including long-lived assets, such as generating plants and nuclear fuel, as well as other assets such as materials and supplies.

Regulated Generation

As of February 21, 2017, FirstEnergy’s regulated generating portfolio consists of 3,790 MWs of diversified capacity contained within the Regulated Distribution segment: 210 MWs consist of JCP&L's 50% ownership interest in the Yards Creek hydroelectric facility in New Jersey; and 3,580 MWs consist of MP's facilities, including 487 MWs from AGC's interest in Bath County that MP partially owns and 11 MWs of MP's 0.49% entitlement from OVEC's generation output. MP's facilities are concentrated primarily in West Virginia. On December 16, 2016, MP issued two RFPs, one to address its generation shortfall previously identified in the IRP filed with the WVPSC on December 30, 2015 and a second RFP to sell its interest in Bath County. The IRP identified a capacity shortfall for MP starting in 2016 and exceeding 700 MWs by 2020 and 850 MWs by 2027. Bids were received by an independent evaluator in February 2017 for both RFPs, including AE Supply's offer of the Pleasants power station (1,300 MWs). Winning bids are expected to be announced in connection with the filing of the appropriate applications for approval of the transactions with the WVPSC and FERC.

Utility Regulation

State Regulation

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

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if 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.

Federal Regulation

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

FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. The Utilities, AE Supply, FES and its subsidiaries, Buchanan Generation and Green Valley each have been authorized by FERC to sell wholesale power in interstate commerce at market-based rates and have a market-based rate tariff on file with FERC, although major wholesale purchases remain subject to regulation by the relevant state commissions. As a condition to selling electricity on a wholesale basis at market-based rates, the Utilities, AE Supply, FES and its subsidiaries, Buchanan Generation and Green Valley, like other entities granted market-based rate authority, must file electronic quarterly reports with FERC listing their sales transactions for the prior quarter. However, consistent with its historical practice, FERC has granted AE Supply, FES and its subsidiaries, Buchanan Generation and Green Valley a waiver from certain reporting, record-keeping and accounting requirements that typically apply to traditional public utilities. Along with market-based rate authority, FERC also granted AE Supply, FES and its subsidiaries, Buchanan Generation and Green Valley blanket authority to issue securities and assume liabilities under Section 204 of the FPA.

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

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

FirstEnergy, including FES, 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, including FES, 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, including FES, 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, including FES, 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.

Regulatory Accounting

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.

The Utilities, AGC, ATSI, PATH and TrAIL recognize, as regulatory assets and regulatory liabilities, costs which FERC and the various state utility commissions, as applicable, have authorized for recovery/return from/to customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets and regulatory liabilities would have been charged to income as incurred. All regulatory assets and liabilities are expected to be recovered/returned from/to customers. Based on current ratemaking procedures, the Utilities, AGC, ATSI, PATH and TrAIL continue to collect cost-based rates for their transmission and distribution services and, in the case of PATH, for its abandoned plant, which remains regulated; accordingly, it is appropriate that the Utilities, AGC, ATSI, PATH and TrAIL continue the application of regulatory accounting to those operations. Regulatory accounting is applied only to the parts of the business that meet the above criteria. If a portion of the business applying regulatory accounting no longer meets those requirements, previously recorded net regulatory assets or liabilities are removed from the balance sheet in accordance with GAAP.

Maryland Regulatory Matters

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to 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 and demand 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. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the goal of 0.97% savings set in PE's plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The costs of the 2015-2017 plan are expected to be approximately $70 million, of which $43 million was incurred through December 31, 2016. 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 February 27, 2013, the MDPSC issued an 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. 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 2013 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 2013 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, as well as 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 Maryland 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 September 26, 2016, the MDPSC initiated a new proceeding to consider an array of issues relating to electric distribution system design, including matters relating to electric vehicles, distributed energy resources, advanced metering infrastructure, energy storage, system planning, rate design, and impacts on low-income customers. Initial comments in the proceeding were filed on October 28, 2016, and the MDPSC held an initial hearing on the matter on December 8-9, 2016. On January 31, 2017, the MDPSC issued a notice establishing five working groups to address these issues over the following eighteen months, and also directed the retention of an outside consultant to prepare a report on costs and benefits of distributed solar generation in Maryland.

New Jersey Regulatory Matters

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS 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.

Pursuant to the NJBPU's March 26, 2015 final order in JCP&L's 2012 rate case proceeding directing that certain studies be completed, on July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which include operational and financial components. The independent consultant conducting the review issued a final report on July 27, 2016, recognizing that JCP&L is meeting the NJBPU requirements and making various operational and financial recommendations. The NJBPU issued an Order on August 24, 2016, that accepted the independent consultant’s final report and directed JCP&L, the Division of Rate Counsel and other interested parties to address the recommendations.

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 filed to participate as a respondent in that proceeding. Briefing has been completed. The oral argument was held on October 25, 2016.

On April 28, 2016, JCP&L filed tariffs with the NJBPU proposing a general rate increase associated with its distribution operations to improve service and benefit customers by supporting equipment maintenance, tree trimming, and inspections of lines, poles and substations, while also compensating for other business and operating expenses. The filing requested approval to increase annual operating revenues by approximately $142.1 million based upon a hybrid test year for the twelve months ending June 30, 2016. On November 30, 2016, JCP&L submitted to the ALJ a Stipulation of Settlement achieved with all the intervening parties providing for an annual $80 million distribution revenue increase, effective January 1, 2017. The ALJ filed an Initial Decision concluding that the Stipulation of Settlement should be approved, and the NJBPU approved the Stipulation of Settlement on December 12, 2016. As part of the Stipulation of Settlement the intervening parties agreed that JCP&L can accelerate the amortization of the 2012 major storm expenses (approximately $19 million annually) that are recovered through the SRC to achieve full recovery by December 31, 2019. On November 23, 2016, JCP&L filed an Amendment to its January 15, 2016 SRC Filing with the NJBPU, requesting that JCP&L be able to accelerate the amortization of the 2012 major storm expenses as agreed to in the Stipulation of Settlement, and a Stipulation of Settlement with NJBPU Staff and the Division of Rate Counsel regarding the SRC Filing was filed on December 27, 2016. The NJBPU approved this Stipulation of Settlement at the January 25, 2017 public meeting.

Ohio Regulatory Matters

The Ohio Companies currently operate under an ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO’s Opinions and Orders issued on March 31, 2016 and October 12, 2016, include Rider DMR, which provides for the Ohio Companies to collect $132.5 million annually for three years, with the possibility of a two-year extension. The Rider DMR will be grossed up for taxes, resulting in an approved amount of approximately $204 million annually. Revenues from the Rider DMR will be excluded from the significantly excessive earnings test for the initial three-year term but the exclusion will be reconsidered upon application for a potential two-year extension. The PUCO set three conditions for continued recovery under Rider DMR: (1) retention of the corporate headquarters and nexus of operations in Akron, Ohio; (2) no change in control of the Ohio Companies; and (3) a demonstration of sufficient progress in the implementation of grid modernization programs approved by the PUCO. ESP IV also continues a base distribution rate freeze through May 31, 2024. In addition, ESP IV continues the supply of power to non-shopping customers at a market-based price set through an auction process.

ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, 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. Other material terms of ESP IV include the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs, an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016), a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045, and contributions, totaling $51 million, to fund energy conservation programs, economic development and job retention in the Ohio Companies' service territory, and a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers, and to establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On April 29, 2016 and May 2, 2016, several parties, including the Ohio Companies, filed applications for rehearing on the Ohio Companies' ESP IV with the PUCO. On September 6, 2016, while the applications for rehearing were still pending before the PUCO, the OCC and NOAC filed a notice of appeal with the Ohio Supreme Court appealing various PUCO and Attorney Examiner Entries on the parties' applications for rehearing. On September 16, 2016, the Ohio Companies intervened and filed a motion to dismiss the appeal. The PUCO resolved such applications for rehearing in the October 12, 2016 Opinion and Order. The OCC and NOAC appeal remains pending before the Ohio Supreme Court.

On November 10, 2016 and November 14, 2016, several parties, including the Ohio Companies, filed additional applications for rehearing on the Ohio Companies’ ESP IV with the PUCO. The Ohio Companies’ application for rehearing challenged, among other things, the PUCO’s failure to adopt the Ohio Companies’ suggested modifications to Rider DMR. The Ohio Companies had previously suggested that a properly designed Rider DMR would be valued at $558 million annually for eight years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio. Other parties’ applications for rehearing argued, among other things, that the PUCO’s adoption of Rider DMR is not supported by law or sufficient evidence. On December 7, 2016, the PUCO granted the applications for rehearing for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO. For additional information, see “FERC Matters - Ohio ESP IV PPA,” below.

Under ORC 4928.66, the Ohio Companies were required to implement energy efficiency programs that achieved a total annual energy savings of 1,990 GWHs and total peak demand reduction of 486 MWs in 2015. On May 12, 2016, the Ohio Companies filed their Energy Efficiency and Peak Demand Reduction Program Status Report indicating compliance with their 2015 statutory benchmarks. In 2016, the Ohio Companies estimated the annual energy savings target and peak demand reduction target will be comparable to the 2015 targets due to the energy efficiency requirements under SB310, which amended ORC 4928.66 to freeze the energy efficiency and peak demand reduction benchmarks for 2015 and 2016. Starting in 2017, ORC 4928.66 requires the energy savings benchmark to increase by 1% and the peak demand reduction benchmark to increase by 0.75% annually thereafter through 2020.

On April 15, 2016, the Ohio Companies filed an application for approval of their three-year energy efficiency portfolio plans for the period from January 1, 2017 through December 31, 2019. The plans as proposed comply with benchmarks contemplated by ORC 4928.66 and provisions of the ESP IV, and include a portfolio of energy efficiency programs targeted to a variety of customer segments, including residential customers, low income customers, small commercial customers, large commercial and industrial customers and governmental entities. On December 9, 2016, the Ohio Companies filed a Stipulation and Recommendation with several parties that contained changes to the plan and a decrease in the plan costs. The Ohio Companies anticipate the cost of the plans will be approximately $268 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies’ existing rate mechanisms. The hearings were held in January 2017.

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, 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. On January 13, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO.

Pennsylvania Regulatory Matters

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.

Following the expiration of the current DSPs, the Pennsylvania Companies will operate under new DSPs for the June 1, 2017 through May 31, 2019 delivery period, which 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 new DSPs, the supply will be provided by wholesale suppliers through 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 new DSPs include modifications to the Pennsylvania Companies’ existing POR programs in order to reduce the level of uncollectible expense 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 were effective through May 31, 2016. Total Phase II costs of these plans were $174 million and are 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' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, with expected costs up to $390 million, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order with full recovery through the reconcilable EE&C riders.

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. 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. On June 9, 2016, the PPUC approved the Pennsylvania Companies’ DSIC riders to be effective July 1, 2016, subject to hearings and refund or reallocation among customers. The four proceedings were consolidated by the ALJ. On January 19, 2017, in the PPUC’s order approving the Pennsylvania Companies’ general rate cases, discussed below, the PPUC referred the issue of whether ADIT should be included in DSIC calculations to the consolidated DSIC proceeding. On February 2, 2017, the parties to the consolidated DSIC proceeding submitted a Joint Settlement to the ALJ to resolve issues referred to by the ALJ in its June 9, 2016 Order, subject to PPUC approval, and would not result in any refund or reallocation among customers. The ADIT issue will be considered separately from the issues resolved in the Joint Settlement Petition of February 2, 2017, and is the sole issue to be litigated in the consolidated DSIC proceeding through a procedural schedule to be determined by the ALJ.

On April 28, 2016, each of the Pennsylvania Companies filed tariffs with the PPUC proposing general rate increases associated with their distribution operations to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements. The filings requested approval to increase annual operating revenues by approximately $140.2 million at ME, $158.8 million at PN, $42.0 million at Penn, and $98.2 million at WP, based upon fully projected future test years for the twelve months ending December 31, 2017 at each of the Pennsylvania Companies. As a result of the enactment of Act 40 of 2016 that terminated the practice of making a CTA when calculating a utility’s federal income taxes for ratemaking purposes, the Pennsylvania Companies submitted supplemental testimony on July 7, 2016, that quantified the value of the elimination of the CTA and outlined their plan for investing 50 percent of that amount in rate base eligible equipment as required by the new law. Formal settlement agreements for each of the Pennsylvania Companies were filed on October 14, 2016, which proposed increases in annual operating revenues of approximately $96 million at

ME, $100 million at PN, $29 million at Penn, and $66 million at WP. One item related to the calculation of DSIC rates was reserved for briefing, with briefs filed by two parties. On November 21, 2016, the ALJ issued a Recommended Decision recommending approval of the settlement agreements and dismissal of the one issue reserved for briefing. Exceptions to that Recommended Decision were filed by one party on December 1, 2016, and reply exceptions were filed by the Pennsylvania Companies on December 8, 2016. On January 19, 2017, the PPUC issued an order approving the settlements and referring the reserved issue to the Pennsylvania Companies' consolidated DSIC proceeding. On February 3, 2017, one party filed a Petition for Reconsideration or Clarification relating to the limited issue of the scope of the record to be transferred to the DSIC proceeding, discussed above. The outcome of this request will not affect the new rates which took effect on January 27, 2017.

West Virginia Regulatory Matters

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking. MP and PE recover net power supply costs, including fuel costs, purchased power costs and related expenses, net of related market sales revenue through the ENEC. MP's and PE's ENEC rate is updated annually.

On March 31, 2016, MP and PE filed with the WVPSC seeking approval of their Phase II energy efficiency program including three MP and PE energy efficiency programs to meet their Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, as agreed to by MP and PE, and approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of the Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. A unanimous settlement was reached by the parties on all issues and presented to the WVPSC on August 18, 2016. An order approving the settlement in full without modification was issued by the WVPSC on September 23, 2016. The Phase II program began initial implementation in November 2016.

The Staff of the WVPSC and the Consumer Advocate Division filed a Show Cause petition on August 5, 2016, requesting that the WVPSC order MP and PE to file and implement RFPs for all future capacity and energy requirements above 100 MWs and that they comply with an RFP settlement provision from the Harrison power station acquisition. MP and PE filed a timely response to the petition arguing for dismissal on September 7, 2016. On October 17, 2016, the WVPSC denied the petition filed by the Staff of the WVPSC and the Consumer Advocate Division and dismissed the case.

On August 16, 2016, MP and PE filed their annual ENEC case proposing an annual increase in rates of approximately $65 million effective January 1, 2017, which is a 4.7% increase over existing rates. The increase is comprised of a $119 million under-recovered balance as of June 30, 2016, and a projected $54 million over-recovery for the 2017 rate effective period. The parties reached a unanimous settlement providing for a $25 million increase beginning January 1, 2017 and keeping ENEC rates at the same level for a two year period. The settlement was presented to the WVPSC at a hearing on November 9, 2016. On December 9, 2016, the WVPSC approved the settlement as submitted.

On August 22, 2016, MP and PE filed an application for approval of a modernization and improvement plan for coal-fired boilers at electric power plants and cost-recovery surcharge proposing an approximate $6.9 million annual increase in rates to be effective May 1, 2017, which is a 0.5% increase over existing rates. The filing is in response to recent legislation by the West Virginia Legislature permitting accelerated recovery of costs related to modernizing and improving coal-fired boilers, including costs related to meeting environmental requirements and reducing emissions. The filing was supplemented on September 28, 2016, to add two additional projects, resulting in an approximate $7.4 million annual increase in rates. The Staff of the WVPSC filed a motion to dismiss the case arguing the new statute was not meant to recover these types of projects, but the WVPSC set the case for hearing for February 21-23, 2017. As part of the annual ENEC settlement described above, the parties agreed that MP and PE will increase ENEC rates to provide for a return of and on MATS/CSPR capital costs incurred during 2016-2017. Accordingly, MP and PE withdrew this case as part of the ENEC approval.

On December 30, 2015, MP filed an IRP with the WVPSC identifying a capacity shortfall starting in 2016 and exceeding 700 MWs by 2020 and 850 MWs by 2027. On June 3, 2016, the WVPSC accepted the IRP finding that IRPs are informational and that it must not approve or disapprove the IRP. MP issued a RFP to address its generation shortfall identified in the IRP on December 16, 2016 along with issuing a second RFP to sell its interest in Bath County. Bids were received by an independent evaluator in February 2017 for both RFPs. MP expects to execute definitive agreements with selected respondent(s) and file the appropriate applications with the WVPSC and FERC by March 15, 2017.

FERC Matters

Ohio ESP IV PPA

On August 4, 2014, the Ohio Companies filed an application with the PUCO seeking approval of their ESP IV. ESP IV included a proposed Rider RRS, which would flow through to customers either charges or credits representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, against the revenues received from selling such output into the PJM markets. The Ohio Companies entered into stipulations which modified ESP IV, and on March 31, 2016, the PUCO issued an Opinion and Order adopting and approving the Ohio Companies’ stipulated ESP IV with modifications. FES and the Ohio Companies entered into the ESP IV PPA on April 1, 2016.

On January 27, 2016, certain parties filed a complaint with FERC against FES and the Ohio Companies requesting FERC review the ESP IV PPA under Section 205 of the FPA. On April 27, 2016, FERC issued an order granting the complaint, prohibiting any transactions under the ESP IV PPA pending authorization by FERC, and directing FES to submit the ESP IV PPA for FERC review if the parties desired to transact under the agreement. FES and the Ohio Companies did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA. FES and the Ohio Companies subsequently advised FERC of this course of action. On January 19, 2017, FERC issued an order accepting compliance filings by FES, its subsidiaries, and the Ohio Companies updating their respective market-based rate tariffs to clarify that affiliate sales restrictions under the tariffs apply to the ESP IV PPA, and also that the ESP IV PPA does not affect certain other waivers of its affiliate restrictions rules FERC previously granted these entities.

On May 2, 2016, the Ohio Companies filed an Application for Rehearing with the PUCO that included a modified Rider RRS proposal that did not involve a FERC-jurisdictional PPA. Several parties subsequently filed protests and comments with FERC alleging, among other things, that the modified Rider RRS constituted a "virtual PPA". FERC rejected these protests in its January 19, 2017 order accepting the updated market-based rate tariffs of FES, its subsidiaries, and the Ohio Companies discussed below.

On March 21, 2016, a number of generation owners filed with FERC a complaint against PJM requesting that FERC expand the MOPR in the PJM Tariff to prevent the alleged artificial suppression of prices in the PJM capacity markets by state-subsidized generation, in particular alleged price suppression that could result from the ESP IV PPA and other similar agreements. The complaint requested that FERC direct PJM to initiate a stakeholder process to develop a long-term MOPR reform for existing resources that receive out-of-market revenue. On January 9, 2017, the generation owners filed to amend their complaint to include challenges to certain legislation and regulatory programs in Illinois. On January 24, 2017, FESC, acting on behalf of its affected affiliates and along with other utility companies, filed a motion to dismiss the amended complaint for various reasons, including that the ESP IV PPA matter is now moot. In addition, on January 30, 2017, FESC along with other utility companies filed a substantive protest to the amended complaint, demonstrating that the question of the proper role for state participation in generation development should be addressed in the PJM stakeholder process. This proceeding remains pending before FERC.

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for certain 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. On June 15, 2016, various parties, including ATSI and the Utilities, filed a settlement agreement at FERC agreeing to apply a combined usage based/socialization approach to cost allocation for charges to transmission customers in the PJM region for transmission projects operating at or above 500 kV. Certain other parties in the proceeding did not agree to the settlement and filed protests to the settlement seeking, among other issues, to strike certain of the evidence advanced by FirstEnergy and certain of the other settling parties in support of the settlement, as well as provided further comments in opposition to the settlement. The PJM TOs responded to the protesting parties' various pleadings and motions. The settlement is pending before FERC.

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. On March 17, 2016, FERC denied FirstEnergy's request for rehearing of FERC's earlier order rejecting the settlement agreement and affirmed its prior ruling that ATSI must submit the cost/benefit analysis.

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 FERC denied on May 19, 2016. On July 15, 2016, the MISO TOs filed an appeal of FERC's orders with the Sixth Circuit. On November 16, 2016, the Sixth Circuit granted FirstEnergy's intervention on behalf of ATSI, the Ohio Companies, and PP, and a procedural schedule has been established. On a related issue, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

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.

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. In February and August 2016, respectively, FERC and the PPUC granted the authorization for PN and ME to contribute their transmission assets to MAIT at book value, together with the approval of related intercompany agreements, including MAIT’s participation in FirstEnergy’s regulated companies' money pool. FirstEnergy subsequently withdrew its request for authorization before the NJBPU to also transfer JCP&L's transmission assets to MAIT.

On October 28, 2016, MAIT and PJM submitted joint applications to FERC requesting authorization for (i) PJM to update its Tariff and other agreements to reflect the withdrawal of ME and PN as TOs, and (ii) MAIT to become a participating PJM TO. FERC approval would authorize MAIT to be a PJM TO, and would permit PJM to implement MAIT’s formula rate on MAIT’s behalf. On January 26, 2017, FERC issued an order granting the requested authorization and MAIT now owns and operates the transmission assets of ME and PN. On January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and asset contributions.

On October 14 and 28, 2016, MAIT submitted applications to FERC requesting authorization to issue equity, short-term debt, and long-term debt. On December 8, 2016, FERC issued an order authorizing the application to issue equity as requested. MAIT is expected to issue short-term debt and participate in the FirstEnergy regulated companies' money pool for working capital, to fund day-to-day operations, and for other general corporate purposes. Over the long-term, MAIT is expected to issue long-term debt to support capital investment and to establish an actual capital structure for ratemaking purposes. On February 3, 2017, MAIT amended its debt authorization application to provide additional information regarding recovery of its investment and debt costs. MAIT requested an order from FERC on the debt authorization by February 28, 2017. FERC’s order remains pending.

MAIT Transmission Formula Rate

On October 28, 2016, MAIT submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective January 1, 2017. On November 30, 2016, various intervenors submitted protests of the proposed MAIT formula rate. Among other things, the protest asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. MAIT filed a response to the protests on December 12, 2016. On December 28, 2016, FERC Staff issued a deficiency letter with respect to the PJM-related application, which also requested additional information regarding MAIT’s proposed formula rate. As a result of the deficiency letter, FERC’s order on the formula rate remains pending. MAIT responded to FERC Staff’s request on January 10, 2017, and requested that FERC issue an order approving the formula rate immediately after consummation of the transaction, which occurred on January 31, 2017. On February 15, 2017, MAIT filed a further answer to certain protesting parties' comments on its January 10th deficiency letter response.

JCP&L Transmission Formula Rate

On October 28, 2016, after withdrawing its request to the NJBPU to transfer its transmission assets to MAIT, JCP&L submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective January 1, 2017. On November 18, 2016, a group of intervenors-including the NJBPU and New Jersey Division of Rate Counsel-filed a protest of the proposed JCP&L transmission rate. Among other things, the protest asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. On December 5, 2016, JCP&L filed a response to the protest. On December 28, 2016, FERC Staff issued a deficiency letter requesting additional information regarding JCP&L’s proposed transmission rate. As a result of the deficiency letter, FERC’s order on the rate remains pending. JCP&L responded to FERC Staff’s request on January 10, 2017, and requested that FERC issue an order approving the formula rate effective January 1, 2017. On February 15, 2017, JCP&L filed a further answer to certain protesting parties' comments on its January 10th deficiency letter response.

Competitive Generation Asset Sale

On February 17, 2017, AE Supply and AGC submitted filings with FERC for authorization to sell four natural gas generating plants and an undivided ownership interest in Bath County to Aspen for approximately $925 million, in an all cash transaction. The four natural gas plants are: Springdale Generating Facility (638 MWs), Chambersburg

Generating Facility (88 MWs), Gans Generating Facility (88 MWs), and Hunlock Creek (45 MWs). The 713 MW ownership interest in Bath County represents AE Supply's indirect ownership interest in the power station. The FERC applications include a request for authorization to transfer the hydroelectric license under Part I of the FPA, and a request for authorization to transfer the FERC-jurisdictional facilities associated with the hydroelectric projects under Part II of the FPA. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once regulatory approval is obtained. The VSCC also must approve the sale of the Bath County Hydro interest. The parties expect to close the transaction in the third quarter of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents. See "Unregulated Competitive Subsidiaries" above for additional information regarding the transaction.

California Claims Litigation

Since 2002, AE Supply has been involved in litigation and claims based on its power sales to the California Energy Resource Scheduling division of the CDWR during 2001-2003. This litigation and claims are related to litigation and claims advanced by the California Attorney General and certain California utilities regarding alleged market manipulation of the wholesale energy markets in California during the 2000-2001 period. AE Supply negotiated a settlement with the California Attorney General and the California utilities and, on August 24, 2016, filed the settlement agreement for FERC approval. The settlement calls for AE Supply to pay, without admission of any liability, \$3.6 million in settlement in principle of all remaining claims that are based on AE Supply's power sales in the western energy markets during the 2001-2003 time period. On October 27, 2016 FERC approved this settlement, and AE Supply paid the settlement shortly thereafter.

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, 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 a 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. On January 19, 2017, FERC issued an order accepting the initial decision in part and denying it in part. Relying on its revised ROE methodology described in FERC Opinion No. 531, FERC reduced the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017. Additionally, FERC allowed recovery of costs related to land acquisitions and dispositions and legal expenses, but disallowed certain costs related to advertising and outreach. PATH filed a request for rehearing with FERC on February 20, 2017, seeking recovery of the advertising and outreach costs and requesting that the ROE be reset to 10.4%.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and its subsidiaries, Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 23, 2016, FESC, on behalf of its affiliates with market-based rate authority, submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. The filings remain pending before FERC.

Capital Requirements

FirstEnergy's capital expenditures for 2017 and 2018 are expected to be approximately $2.8 billion and $2.7 billion, respectively. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

Capital expenditures for 2016 and anticipated expenditures for 2017 and 2018 by reportable segment are included below:

Reportable Segment	2016 Actual[1]	2016 Pension/OPEB Mark-to-Market Capital Costs	2016 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2017 Forecast[2]	2018 Forecast[2]
	(In millions)				
Regulated Distribution	$1,327	$ 46	$ 1,281	$ 1,325	$ 1,305
Regulated Transmission[4]	1,005	4	1,001	1,000	1,000
CES[3]	547	(3)	550	365	290
Corporate/Other	93	—	93	95	90
Total	$2,972	$ 47	$ 2,925	$ 2,785	$ 2,685

[1] Includes an increase of approximately $47 million related to the capital component of the pension and OPEB mark-to-market adjustment.
[2] Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.
[3] Approximately $35 million and $20 million of forecasted annual capital expenditures are associated with the Pleasants power station for 2017 and 2018, respectively. On February 3, 2017, AE Supply offered the Pleasants power station into MP's RFP, as discussed above.
[4] 2018 Forecast represents the mid-point of Regulated Transmission's 2018 forecasted capital expenditures of $800 million to $1,200 million.

Additionally, planned capital expenditures in 2018 and 2019 for Regulated Distribution are approximately $1.3 billion while planned capital expenditures for Regulated Transmission are expected to be approximately $800 million to $1.2 billion, annually, from 2019 through 2021.

Capital expenditures for 2016 and anticipated expenditures for 2017 by subsidiary are included in the following table (anticipated capital expenditures by subsidiary for 2018 are not finalized):

Operating Company	2016 Actual[1]	2016 Pension/OPEB Mark-to-Market Capital Costs	2016 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2017 Forecast[2]
	(In millions)			
OE	$163	$ 7	$ 156	$ 145
Penn	50	3	47	45
CEI	158	25	133	125
TE	46	2	44	45
JCP&L	399	17	382	350
ME	139	6	133	135
PN	184	1	183	160
MP	242	(6)	248	250

PE	103	(5)	108	125
WP	166	—	166	205
ATSI	487	—	487	420
TrAIL	217	—	217	60
FES	470	(3)	473	320
AE Supply(3)	63	—	63	45
MAIT	—	—	—	260
Other subsidiaries	85	—	85	95
Total	$2,972	$ 47	$ 2,925	$ 2,785

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(1) Includes an increase of approximately $47 million related to the capital component of the pension and OPEB mark-to-market adjustment.
(2) Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.
(3) Approximately $35 million of forecasted annual capital expenditures are associated with the Pleasants power station for 2017. On February 3, 2017, AE Supply offered the Pleasants power station into MP's RFP, as discussed above.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2016, excluding capital leases for the next five years. 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.

	2017	2018-2021	Total
	(In millions)		
FirstEnergy	$1,641	$ 6,031	$7,672
FES	$163	$ 2,435	$2,598

The following tables display consolidated operating lease commitments as of December 31, 2016.

Operating Leases	FirstEnergy
	(In millions)
2017[1]	$ 125
2018	142
2019	123
2020	97
2021	119
Years thereafter	1,351
Total minimum lease payments	$ 1,957

(1) Includes a $3 million payment PNBV Trust will receive associated with certain sale and leaseback transactions. These arrangements, which expire in 2017, effectively reduce lease costs related to those transactions.

Operating Leases	FES
	(In millions)
2017	$ 82
2018	101
2019	97
2020	68
2021	93
Years thereafter	1,222
Total minimum lease payments	$ 1,663

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.

FE, and its utility and transmission subsidiaries, expect their existing sources of liquidity to remain sufficient to meet their respective anticipated obligations. In addition to internal sources to fund liquidity and capital requirements for

2017 and beyond, FE and its utility and transmission subsidiaries expect 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, including cash requirements to fund Regulated Transmission's capital program, may be met through a combination of an additional $500 million of equity in each year 2017 through 2019, and new long-term debt, in each case, subject to market conditions and other factors. FirstEnergy also expects to issue long-term debt at certain Utilities to, among other things, refinance short-term and maturing long-term debt, subject to market conditions and other factors.

FirstEnergy’s unregulated subsidiaries, specifically FES and AE Supply, expect to rely on, in the case of AE Supply, internal sources, the unregulated companies' money pool, and proceeds generated from previously disclosed asset sales, subject to closing, and with respect to FES, a two-year secured line of credit with FE of up to $500 million, as further described below. Additionally, FES subsidiaries have debt maturities in 2017 and 2018 of $130 million and $515 million, respectively. The inability to refinance such debt maturities could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations,

(ii) additional borrowings under its credit facility with FE, (iii) further asset sales or plant deactivations, and/or (iv) seek protection under U.S. bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under U.S. bankruptcy laws.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016.

Any financing plans by FE or any of its subsidiaries, including the issuance of equity and debt, and the refinancing of short-term and maturing long-term debt, are subject to market conditions and other factors, such as the impact of the current energy and capacity markets and potential credit rating changes. No assurance can be given that any such issuances, financing or refinancing, as the case may be, will be completed as anticipated. Any delay in the completion of financing plans could require FE or any of its subsidiaries to utilize short-term borrowing capacity, which would impact available liquidity. In particular, FES may borrow under its credit facility with FE, to the extent available, to refinance debt maturities and mandatory purchase obligations, which would impact available liquidity for FES and, FE to the extent it funds any such borrowings through its facility and/or cash. In addition, FE and its subsidiaries expect to continually evaluate any planned financings, which may result in changes from time to time.

On December 6, 2016, FE and certain subsidiaries entered into new five-year syndicated credit facilities available through December 6, 2021, and concurrently terminated existing syndicated credit facilities that were to expire March 31, 2019, as follows:

- FE and the Utilities entered into a new $4 billion revolving credit facility, which represents an increase of $500 million over the existing $3.5 billion facility it replaced,
- FET and its subsidiaries entered into a $1 billion revolving credit facility, which replaced their existing $1 billion facility, and
- FES and AE Supply terminated their unsecured $1.5 billion credit facility (commitments of $900 million and $600 million for FES and AE Supply, respectively) and FES entered into a new, two-year secured credit facility with FE in which FE provided a committed line of credit to FES of up to $500 million and additional credit support of up to $200 million to cover a $169 million surety bond for the benefit of the PA DEP with respect to LBR, and other bonds as designated in writing to FE. In connection with the cancellation of the prior FES/AE Supply facility and entry into the new FES secured facility with FE, certain commitments and amendments associated with shared services and operational matters were made including, without limitation, as follows: (i) FE reaffirmed its obligations under the Intercompany Tax Allocation Agreement, and (ii) amendments to the Service Agreement by and among FESC, FES, FG and NG, to prevent termination until the earlier of December 31, 2018, or a change in control of FES or its subsidiaries.

FE, the Utilities and FET and its subsidiaries may use borrowings under their new facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. FES expects to use its new facility with FE to conduct its ordinary course of business in lieu of borrowing under the unregulated money pool. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million).

Additionally, on December 6, 2016, FE terminated its existing $1 billion and $200 million term loan credit agreements and entered into a new $1.2 billion five-year syndicated term loan credit agreement. The term loan contains covenants and other terms and conditions substantially similar to those of the FE revolving credit facility described above, including a consolidated debt to total capitalization ratio and minimum interest coverage ratio requirement.

Under the terms of the new FE and FET credit facilities, each borrower is required to maintain a consolidated debt to total capitalization ratio, as defined, of no more than 0.65 to 1.00, or in the case of FET, 0.75 to 1.00. For purposes of calculating its ratio, FE is permitted certain adjustments to total capitalization including (i) an exclusion for certain previously incurred after-tax, non-cash write-downs and non-cash charges of approximately $2.75 billion and (ii) a new exclusion for additional after-tax, non-cash write-downs and non-cash charges up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and each of their subsidiaries. Additionally, under the new credit facility, FE is now also required to maintain a minimum interest coverage ratio of 1.75 to 1.00 until December 31, 2017, 2.00 to 1.00 beginning January 1, 2018 until December 31, 2018, 2.25 to 1.00 beginning January 1, 2019 until December 31, 2019, and 2.50 to 1.00 beginning January 1, 2020 until December 31, 2021. FE and each of the other borrowers under the new FE and FET credit facilities are currently in compliance with these financial covenants. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 described above are excluded from FE's calculation of total capitalization pursuant to the new $5.5 billion after-tax exclusion referenced in (ii) above consistent with the terms of the facility. Other terms of the new FE credit facility exclude FES and AE Supply from the definition of “significant subsidiaries,” which removes them from FE’s covenants and defaults resulting from adverse judgments in excess of $100 million and eliminates lender approvals previously required for FES and AE Supply asset sales.

Outstanding alternate base rate advances under the new FE and FET facilities will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to the applicable borrower’s then-current senior unsecured non-credit enhanced debt ratings (reference ratings) plus the highest of (i) the “prime rate” published by the Wall Street Journal from time to time, (ii) the sum of 1/2 of 1% per annum plus the federal funds rate in effect from time to time and (iii) the LIBOR for a one-month interest period plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to the applicable borrower’s reference ratings. Swing line loans under the new FE facility will bear interest at a rate per annum equal to the sum of the alternate base rate plus an applicable margin determined by reference to the applicable borrower's reference ratings. Changes in reference ratings of a borrower would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

The initial borrowing under the new $1.2 billion FE 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. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE's reference ratings plus the highest of (i) the administrative agent's publicly-announced "prime rate", (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE's reference ratings. Changes in FE's reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

On February 16, 2017, FE entered into two separate $125 million three-year term loan credit agreements with Bank of America, N.A. and The Bank of Nova Scotia, respectively, the proceeds of which were used to reduce short-term debt. The terms and conditions of these new credit agreements are substantially similar to the December 6, 2016, $1.2 billion five-year syndicated term loan credit agreement.

FirstEnergy had $2,675 million and $1,708 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FirstEnergy's available liquidity from external sources as of January 31, 2017 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2021	$4,000	$ 1,341
FET[2]	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 2,341
		Cash	—	308
		Total	$5,000	$ 2,649

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

FES had $101 million (payable to AE Supply) and $8 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FES' available liquidity as of January 31, 2017 was as follows:

Type	Commitment	Available Liquidity
	(In millions)	
Two-year secured credit facility with FE	$ 500	$ 500
Cash	—	2
	$ 500	$ 502

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Nuclear Operating Licenses

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

Station	In-Service Date	Current License Expiration
Beaver Valley Unit 1	1976	2036
Beaver Valley Unit 2	1987	2047
Perry	1986	2026
Davis-Besse	1977	2037

Nuclear Regulation

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2016, FirstEnergy had approximately $2.5 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 FES no longer maintains investment grade credit ratings from either S&P or Moody’s, NG funded a $10 million supplemental trust in 2016 in lieu of the FES parental guarantee that would be required to support the decommissioning of the spent fuel storage facilities. The termination of the FES parental guarantee is subject to NRC review. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantees, as appropriate.

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 to the NRC related to the laminar cracking in the Shield Building.

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. Although a majority of the necessary modifications and upgrades at FirstEnergy’s nuclear facilities have been implemented, the improvements still remain subject to regulatory approval.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. In addition to the $500 million credit facility with FE discussed above, FE is working with FES to establish conditional credit support on terms and conditions to be agreed upon for the $400 million FES parental support agreement that is currently in place for the benefit of NG in the event that FES is unable to provide the necessary support to NG.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.3 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13 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-$506 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, NG purchases insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. NG is a Member Insured of NEIL, which provides coverage for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. NG, as the Member Insured and each entity with an insurable interest, purchases policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.40 billion (NG-$1.39 billion) for replacement power costs incurred during an outage after an initial 12-week waiting period.

NG, as the Member Insured and each entity with an insurable interest, is insured under property damage insurance provided by NEIL. 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. Member Insureds of NEIL pay annual premiums and are subject to retrospective premium assessments if losses exceed the accumulated funds available to the insurer. NG purchases insurance through NEIL that will pay its obligation in the event a retrospective premium call is made by NEIL, subject to the terms of the policy.

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 NG's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy’s insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

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

Environmental Matters

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

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 issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Various states and other stakeholders appealed the CSAPR update rule to the D.C. Circuit in November and December 2016. Depending on the outcome of the appeals and on how the EPA and the states implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's and FES' operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The 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 the 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 material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State of Delaware's CAA Section 126 petition by six months to April 7, 2017. In November 2016, the State of Maryland filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 36 EGUs, including Harrison Units 1, 2 and 3, Mansfield Unit 1 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition seeks NOx emission rate limits for the 36 EGUs by May 1, 2017. On January 3, 2017, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to July 15, 2017. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

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. 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 $286 million has been spent through December 31, 2016 ($125 million at CES and $161 million at Regulated Distribution).

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 event 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, all plants covered by this contract 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 under the contract through 2025. On May 31, 2016, the parties agreed to a stipulation that if FG's force majeure defense is determined to be wholly or partially invalid, liquidated damages are the sole remedy available to BNSF and CSX. The arbitration panel consolidated the claims and held a liability hearing from November 28, 2016, through December 9, 2016, and, if necessary, a damages hearing is scheduled to begin on May 8, 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearing proceedings, which are scheduled to conclude February 24, 2017. 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. FG intends to vigorously assert its 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. Refer to "The Companies - Competitive Generation" above for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS who are the counterparties to the coal transportation contract covering the delivery of 2.5 million tons annually through 2025, for FG's coal-fired Bay Shore Units 2-4, deactivated on September 1, 2012, as a result of the EPA's MATS and for FG's W.H. Sammis Plant. The demand for arbitration was submitted to the AAA office in Washington, D.C. against FG alleging, among other things, that FG breached the agreement in 2015 and 2016 and repudiated the agreement for 2017-2025. The counterparties are seeking, among other things, damages, including lost profits through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. FG intends to vigorously assert its position in this arbitration proceeding. If it were ultimately determined that the force majeure provisions or other defenses do not excuse the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. Refer to "The Companies - Competitive Generation" above for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced in the above arbitration proceedings, FG paid approximately $70 million in the aggregate in liquidated damages to settle delivery shortfalls in 2014 related to its deactivated plants, which approximated full liquidated damages under the agreements for such year related to the plant deactivations. Liquidated damages for the period 2015-2025 remain in dispute under both coal transportation agreements.

As to a specific coal supply agreement, AE Supply asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, the coal supplier commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. AE Supply has 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 approximately 5.5 million tons remaining under the contract for delivery. At this time, AE Supply cannot estimate the loss or range of loss regarding the ongoing 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, March 27, 2013 and October 18, 2016, 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

FirstEnergy has established a goal to reduce CO_2 emissions by 90% below 2005 levels by 2045. 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.

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. 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. The EPA released its final regulations in August 2015 (which have been stayed by the U.S. Supreme Court), 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. 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, 2016, 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 material.

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 was ratified by the requisite number of countries (i.e. at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius are effective on November 4, 2016. It remains unclear whether and how the results of the 2016 United States election could impact the regulation of GHG emissions at the federal and state level. 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 material 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 material.

On September 30, 2015, the EPA finalized new, more stringent effluent limits for the Steam Electric Power Generating category (40 CFR Part 423) 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 not currently expected, any changes in timing and closure plan requirements in the future, including changes resulting from the strategic review at CES, could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG 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 CCRs from the Bruce Mansfield plant are being beneficially reused with the majority used for reclamation of a site owned by the Marshall County Coal Company in Moundsville, W. Va. and the remainder recycled into drywall by National Gypsum. These beneficial reuse options should be sufficient for ongoing plant operations, however, the Bruce Mansfield plant is pursuing other options. 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 Notices of Appeal 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, 2016 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 $137 million have been accrued through December 31, 2016. Included in the total are accrued liabilities of approximately $89 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 loss cannot be determined or reasonably estimated at this time.

Fuel Supply

FirstEnergy currently has coal contracts with various terms to acquire approximately 18 million tons of coal for the year 2017, which is approximately 88% of its forecasted 2017 coal requirements. This contracted coal is produced primarily from mines located in Ohio, Pennsylvania, and West Virginia. The contracts expire at various times through 2028. See "Environmental Matters" for additional information pertaining to the impact of increased environmental regulations on coal supply and transportation contracts applicable to certain deactivated coal-fired generating units and related pending disputes.

FirstEnergy has contracts for all uranium requirements through 2018 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2018 and partially fill requirements through 2024. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2020. A portion of enrichment requirements is also contracted for through 2030. Fabrication services for fuel assemblies are contracted for both Beaver Valley units through 2029 and Davis-Besse through 2025 and through the current operating license period for Perry.

On-site spent fuel storage facilities are currently adequate for the nuclear operating units. An on-site dry cask storage facility has been constructed at Beaver Valley sufficient to extend spent fuel storage capacity through the end of current operating licenses at Beaver Valley Unit 1 and Beaver Valley Unity 2. Davis-Besse is planning to resume dry cask storage operations in 2017, which will extend on-site spent fuel storage capacity through the end of its recently extended operating license. Perry has constructed an on-site dry cask storage facility, has completed three dry cask storage loading campaigns, and has planned to conduct additional dry cask storage loading campaigns that will provide for sufficient spent fuel storage capacity through 2046 (end of current operating license plus a 20-year operating license extension).

The Federal Nuclear Waste Policy Act of 1982 provided for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. NG has contracts with the DOE for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. Yucca Mountain was approved in 2002 as a repository for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. The DOE submitted the license application for Yucca Mountain to the NRC on June 3, 2008. Efforts to complete the Yucca Mountain repository have been suspended and a Federal review of potential alternative strategies has been performed.

In light of this uncertainty, FirstEnergy has made arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

Natural gas demand at the combined cycle and peaking units is forecasted at approximately 31 million cubic feet in 2017. Fuel oil and natural gas are also used to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so. Requirements are expected to range between 7.5 and 8.5 million gallons per year over the next five years.

System Demand

The 2016 maximum hourly demand for each of the Utilities was:

- OE—5,655 MW on August 11, 2016;
- Penn—994 MW on September 7, 2016;
- CEI—4,193 MW on September 7, 2016;
- TE—2,171 MW on September 7, 2016;
- JCP&L—5,955 MW on August 12, 2016;
- ME—2,904 MW on July 25, 2016;
- PN—2,890 MW on December 15, 2016;
- MP—2,053 MW on August 11, 2016;
- PE—3,049 MW on February 12, 2016; and
- WP—3,947 MW on July 25, 2016.

Supply Plan

Regulated Commodity Sourcing

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

Unregulated Commodity Sourcing

The CES segment, through FES and AE Supply, primarily provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES and AE Supply provide the power requirements of their competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

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

Regional Reliability

All of FirstEnergy's facilities are located within the PJM Region and operate under the reliability oversight of a regional entity known as RFC. This regional entity operates under the oversight of NERC in accordance with a delegation agreement approved by FERC.

Competition

Within FirstEnergy’s Regulated Distribution segment, generally there is no competition for electric distribution service in the Utilities’ respective service territories in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. Additionally, there has traditionally been no competition for transmission service in PJM. However, pursuant to FERC’s Order No. 1000 and subject to state and local siting and permitting approvals, non-incumbent developers now can compete for certain PJM transmission projects in the service territories of FirstEnergy’s Regulated Transmission segment. This could result in additional competition to build transmission facilities in the Regulated Transmission segment’s service territories while also allowing the Regulated Transmission segment the opportunity to seek to build facilities in non-incumbent service territories.

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

Seasonality

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

Research and Development

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

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

Executive Officers as of February 21, 2017

Name	Age	Positions Held During Past Five Years	Dates
G. D. Benz	57	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	2012-2015
L. M. Cavalier	65	Chief Human Resource Officer (B)	2015-present
		Senior Vice President, Human Resources (B)	*-2015
D. M. Chack	66	Senior Vice President, Marketing and Branding (B)	2015-present
		President, Ohio Operations (B)	*-2015
		Vice President (C)	*-2015
M. J. Dowling	52	Senior Vice President, External Affairs (B)	*-present
B. L. Gaines	63	Senior Vice President, Corporate Services and Chief Information Officer (B)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)	*-2012
C. E. Jones	61	President and Chief Executive Officer (A)(B)	2015-present
		Chief Executive Officer (F)	2015-2017
		President (C)(D)(H)(I)(L)	*-2015
		Executive Vice President & President, FirstEnergy Utilities (A)(B)	2014
		Senior Vice President & President, FirstEnergy Utilities (B)	*-2013
J. H. Lash	66	Executive Vice President & President, FE Generation (A)(B)	2015-present
		President (G)	*-present
		President (J)	*-2016
		President, FE Generation (B)	*-2015
		Chief Nuclear Officer (F)	*-2012
C. D. Lasky	54	Senior Vice President, Human Resources (B)	2015-present
		Vice President, Fossil Operations (J)	2014-2015
		Vice President (G)	*-2015
		Vice President, Fossil Operations & Engineering (J)	2014
		Vice President, Fossil Fleet Operations (J)	*-2013
J. F. Pearson	62	Executive Vice President and Chief Financial Officer (N)	2016-present
		Executive Vice President and Chief Financial Officer (A)(B)(C)(D)(H)(I)(L)	2015-present
		Executive Vice President and Chief Financial Officer (F)(G)	2015-2017
		Executive Vice President and Chief Financial Officer (E)(J)	2015-2016
		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)(G)(H)(I)(J)(L)	*-2012
R. P. Reffner	66	Vice President and General Counsel (N)	2016-present
		Vice President and General Counsel (B)(C)(D)(H)(I)(L)	2014-present

		Vice President and General Counsel (F)(G)	2014-2017
		Vice President and General Counsel (E)(J)	2014-2016
		Vice President, Legal (B)	*-2013
D. R. Schneider	55	President (E)	*-present
		Chairman of the Board (E)	2016-present
S. E. Strah	53	President (N)	2016-present
		Senior Vice President & President, FirstEnergy Utilities (B)	2015-present
		President (C)(D)(H)(I)(L)	2015-present
		Vice President, Distribution Support (B)	*-2015
K. J. Taylor	43	Vice President and Controller (N)	2016-present
		Vice President, Controller and Chief Accounting Officer (A)(B)	2013-present
		Vice President and Controller (C)(D)(H)(I)(L)	2013-present
		Vice President and Controller (F)(G)	2013-2017
		Vice President and Controller (E)(J)	2013-2016
		Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012-2013
		Assistant Controller (A)(B)(C)(D)(H)(I)(L)	*-2012
		Assistant Controller (E)(F)(G)(J)	2012
L. L. Vespoli	57	Executive Vice President, Corporate Strategy, Regulatory Affairs & Chief Legal Officer (A)(B)(C)(D)(H)(I)(L)(N)	2016-present
		Executive Vice President, Corporate Strategy, Regulatory Affairs & Chief Legal Officer (F)(G)	2016-2017
		Executive Vice President, Corporate Strategy, Regulatory Affairs & Chief Legal Officer (E)(J)	2016
		Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2014-2016
		Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	*-2013

* Indicates position held at least since January 1, 2012	(E) Denotes executive officer of FES	(J) Denotes executive officer of FG
(A) Denotes executive officer of FE	(F) Denotes executive officer of FENOC	(K) Denotes executive officer of OE
(B) Denotes executive officer of FESC	(G) Denotes executive officer of AGC	(L) Denotes executive officer of ATSI
(C) Denotes executive officer of OE, CEI and TE	(H) Denotes executive officer of MP, PE and WP	(M) Denotes executive officer of CEI
(D) Denotes executive officer of ME, PN and Penn	(I) Denotes executive officer of TrAIL and FET	(N) Denotes executive officer of MAIT

Employees

As of December 31, 2016, FirstEnergy’s subsidiaries had 15,707 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	4,429	749
OE	1,090	706
CEI	920	610
TE	327	235
Penn	183	129
JCP&L	1,347	1,041
ME	653	489
PN	728	475
FES	77	—
FG	1,654	1,031
FENOC	2,487	1,068
MP	622	401
PE	482	299
WP	708	452
Total	15,707	7,685

As of December 31, 2016, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 6,585 of FirstEnergy's employees. There are 22 CBAs between FirstEnergy's subsidiaries and its unions, which have three, four or five year terms. In 2016, certain of FirstEnergy's subsidiaries reached new agreements on CBAs with seven different IBEW locals, covering approximately 1,417 employees.

On January 25, 2016, IBEW Local 459, which represents approximately 371 employees in PN, ratified a new agreement that will expire May 14, 2021. On March 17, 2016, OPEIU Local 19, which represents approximately 104 employees at TE, the Davis-Besse nuclear plant and the Bay Shore generating station ratified a contract that will expire on February 29, 2020. On March 21, 2016, UWUA Local 270 PT, which represents approximately 67 employees at the Perry nuclear plant, ratified a new agreement that will expire on November 18, 2018. On April 18, 2016, IBEW Local 2357, which represents approximately 218 employees at MP, ratified a new agreement that will expire February 28, 2021. On September 9, 2016, IBEW Local 1413, which represents approximately 138 security personnel at the Davis-Besse nuclear plant, ratified a contract that will expire September 9, 2020. On September 29, 2016, IBEW Local 1194, which represents approximately 255 employees at OE, ratified a new agreement that will expire September 3, 2019. On November 3, 2016, IBEW Local 29, which represents approximately 379 employees at the Beaver Valley nuclear plant ratified a contract that will expire September 30, 2021. On November 3, 2016, IBEW Local 29 MP, which represents approximately 18 Maintenance Planners at the Beaver Valley nuclear plant ratified a new contract that will expire February 28, 2022. On November 20, 2016, IBEW Local 50, which represents approximately 38 employees at MP, ratified a new contract that will expire February 28, 2022.

The agreement with IBEW Local 272, which represents approximately 220 employees at the Bruce Mansfield plant, expired on February 15, 2014. On October 27, 2015, following nearly two years of bargaining, FirstEnergy declared impasse and implemented terms and conditions of employment from its last comprehensive offer to settle. FirstEnergy continues to engage in discussions with IBEW Local 272, and work continuation plans are in place in the event of a work stoppage.

FirstEnergy Website and Other Social Media Sites and Applications

Each of the registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through the "Investors" page of FirstEnergy's Internet website at www.firstenergycorp.com. The public may read and copy any reports or other information that the registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the SEC's public reference room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services and the website maintained by the SEC at www.sec.gov.

These SEC filings are posted on FirstEnergy's website as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post additional important information including press releases, investor presentations and notices of upcoming events, under the "Investors" section of FirstEnergy's Internet website and recognize FirstEnergy's Internet website as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of postings to the website by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet website FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under Regulation FD. Information contained on FirstEnergy’s Internet website, posted on FirstEnergy's Facebook® page or disseminated through Twitter®, and any corresponding applications, shall not be deemed incorporated into, or to be part of, this report.

ITEM 1A. RISK FACTORS

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

Risks Related to the Transition to a Fully Regulated Utility

We Have Taken a Series of Actions to Focus Our Growth on Our Regulated Operations, Particularly Within the Regulated Transmission Segment. Whether This Investment Strategy Will Deliver the Desired Result is Subject to Certain Risks Which Could Adversely Affect Our Results of Operations and Financial Condition in the Future

We focus on capitalizing on investment opportunities available to our regulated operations - particularly within our Regulated Transmission segment - as we focus on delivering enhanced customer service and reliability. The success of these efforts will depend, in part, on successful recovery of our transmission investments. Factors that may affect rate recovery of our transmission investments include: (1) FERC’s timely approval of rates to recover such investments; (2) whether the investments are included in PJM's RTEP; (3) FERC's evolving policies with respect to incentive rates for transmission assets; (4) FERC's evolving policies with respect to the calculation of the base ROE component of transmission rates, as articulated in FERC's Opinion No. 531 and related orders; (5) consideration of the objections of those who oppose such investments and their recovery; and (6) timely development, construction, and operation of the new facilities.

The success of these efforts will also depend, in part, on any future distribution rate cases and transmission rate filings in the states where our Utilities operate. Any denial of, or delay in, the approval of any future distribution or transmission rate requests could restrict us from fully recovering our cost of service, may impose risks on the Regulated Transmission and Regulated Distribution operations, and could have a material adverse effect on our regulatory strategy and results of operations.

Our efforts also could be impacted by our ability to finance the proposed expansion projects while maintaining adequate liquidity. There can be no assurance that our efforts to reflect a more regulated business profile will deliver the desired result which could adversely affect our future results of operations and financial condition.

Consistent With Our Strategy to Be A Fully Regulated Utility, We Intend to Exit the Competitive Generation Business; Failure to Successfully Implement Strategic Alternatives for the CES Segment May Further Negatively and Materially Impact the Future Results of Operations and Financial Condition of FirstEnergy and FES, and Regardless of the Viability or Success of the Sale of Certain AE Supply Generation Assets and Other Strategic Alternatives for the CES Segment, Certain Events May Significantly Increase Cash Flow and Liquidity Risks, and May Cause FES and, Possibly, FENOC to Take Other Actions, Including Debt Restructuring or Seeking Protection under the U.S. Bankruptcy Laws

Depressed prices in the wholesale energy and capacity markets insufficient results from recent capacity auctions and anemic demand forecasts that have lowered the value of the business continue to challenge the CES segment, including FES. Consequently, as previously disclosed in FirstEnergy‘s and FES’ prior SEC filings and as further discussed in "FirstEnergy’s Management’s Discussion and Analysis of Financial Condition and Results of Operations" and "FES’ Narrative Analysis of Results of Operations" in this Annual Report on Form 10-K for the year ended December 31, 2016, FirstEnergy is engaged in a strategic review of its competitive operations focused on the sale of gas and hydroelectric units at AE Supply, as well as exploring all alternatives for the remaining generation assets at

FES and AE Supply.

These alternatives include, but are not limited to, (i) the sale or deactivation of additional generating units and other assets within CES, including FES, (ii) legislative or regulatory solutions for generation assets that recognize their environmental or energy security benefits, (iii) restructuring FES debt with its creditors, and/or (iv) seeking protection under U.S. bankruptcy laws for FES, and possibly FENOC. Management anticipates that the viability of these alternatives will be determined in the near term with a target to implement these strategic options by mid-2018. Each of FE and FES (together with FENOC) have engaged separate advisors to assist them as they explore these strategic alternatives and other options if these alternatives cannot be implemented. No assurance can be given, however, that these strategic alternatives are viable or will be achieved or sufficiently realized or the time frame in which they may be achieved.

Regardless of the viability or success of the sales of CES generation assets and other strategic alternatives for the CES business discussed above, CES, including FES, faces significant cash flow and liquidity risks including, but not limited to the following:

- requests to post additional collateral or accelerate payments

- adverse outcomes in previously disclosed disputes regarding long-term coal and coal transportation contracts; and
- the inability to refinance debt maturities at FES subsidiaries of $130 million, $515 million, and $323 million in 2017, 2018 and 2019, respectively, and in the event AE Supply's pending sale of assets is not consummated, $155 million in 2019 at AE Supply, in each case, at attractive rates or at all.

Any one of these events, even if the alternatives outlined above or any other viable business alternatives are implemented, could require FES to (i) restructure debt and other financial obligations, or (ii) borrow additional funds from FE under its secured credit facility. In addition, FES, and possibly FENOC, may determine to seek protection under U.S. bankruptcy laws regardless of the viability of one or more strategic alternatives.

A near-term deactivation of one or more of the nuclear generating units could have a material adverse effect on FirstEnergy's and/or FES' business, financial condition and results of operations as the NDTs may be insufficient to address all radiological decommissioning costs thus requiring financial guarantees or additional contributions, which could be significant. Additionally, the funds from the NDTs may be restricted from being used to address other significant costs resulting from a near-term deactivation, such as the costs associated with storing spent nuclear fuel onsite.

Adverse judgments or outcomes in ongoing disputes could result in one or more events of default under various agreements related to the indebtedness of FES. Additionally, although the recent amendment to FE's credit facility revised the debt to total capitalization ratio covenant to exclude non-cash charges up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and each of their subsidiaries, charges beyond that amount could result in an event of default related to the indebtedness of FE, which may have a further material adverse effect on the results of operations and financial condition of FE.

There is Substantial Uncertainty as to FES' Ability to Continue as a Going Concern and Substantial Risk That It May be Necessary for FES, and possibly FENOC, to Seek Protection Under U.S. Bankruptcy Laws, Which Would Have a Material Adverse Impact on FirstEnergy's and FES' Business, Financial Condition, Results of Operations and Cash Flows

Based upon continued depressed prices in the wholesale energy and capacity markets, weak demand for electricity and anemic demand forecasts, FES' cash flow from operations may be insufficient to repay its indebtedness or trade payables in the long-term. Although management is exploring capital and other cost reductions, asset sales, and other options to improve cash flow as well as continuing with legislative efforts to explore a regulatory type solution, the obligations and their impact to liquidity raise substantial doubt about FES' ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern. However, the accompanying financial statements do not include any adjustments related to the recoverability and classification of recorded assets or the amounts and classification of liabilities that might result from the uncertainty associated with the ability to meet obligations as they come due.

Although each of FirstEnergy and FES (together with FENOC) have engaged separate financial and legal advisors to assist with the evaluation of various strategic alternatives and to address the liquidity needs and the current capitalization of FES, there can be no assurance FES will be successful in pursuing such alternatives and due to FES' financial condition, there is a substantial risk that it may be necessary for FES, and possibly FENOC, to seek protection under U.S. bankruptcy laws. An FES bankruptcy proceeding would have a material adverse effect on FES' business, financial condition, results of operations and cash flows and could have a material adverse effect on FirstEnergy's business, financial condition, results of operations and cash flows. Management of FirstEnergy and FES would be required to spend a significant amount of time and effort dealing with the bankruptcy proceeding instead of focusing on their business operations. In addition, it is expected that prior to the commencement of any such proceeding, FES will be fully drawn under its new $500 million secured credit facility from FE, which FE would likely fund by borrowing under its bank facility. A bankruptcy proceeding at FES also may make it more difficult to retain, attract or replace management and other key personnel. Moreover, creditors of FES may attempt to assert claims against FirstEnergy that may require significant effort and money to defend. There can be no assurance that

FirstEnergy would be successful in defending against any such claims. The costs and the uncertainty of potential liabilities during the pendency of an FES bankruptcy proceeding could have a material and adverse impact on FirstEnergy's and FES' business, financial condition, results of operations and cash flows.

FirstEnergy and FES May Not Be Successful in Pursuing and/or Consummating Sales of Generating Assets, Which Could Result in Further Substantial Write-Downs and Impairments of Assets and Have a Material Adverse Effect on the Results of Operations and Financial Condition of FirstEnergy and FES

Since beginning their strategic review of the CES segment, FirstEnergy and FES have been pursuing the sale of certain generating and other assets. Because of the current financial condition of FES, those sales may be more difficult to execute at market values or at all.

In this regard, on January 18, 2017, AE Supply and AGC entered into an asset purchase agreement for the sale of its Springdale, Chambersburg, Gans and Hunlock gas facilities and AE Supply's share of AGC's ownership interest in Bath County, with a combined capacity of 1,572 MWs. Under the terms of the agreement, the facilities would be purchased for an all cash purchase price of approximately $925 million. The transaction is expected to close in the third quarter of 2017, subject to satisfaction of various customary and other closing conditions, including regulatory approvals, the receipt of third party consents and the satisfaction and discharge of AE Supply's senior note indenture, under which there is approximately $305 million of indebtedness outstanding, that is expected to require a "make-whole" payment anticipated to be approximately $100 million based on current interest rates. Many of the conditions to closing are outside the control of AE Supply and AGC and there is no assurance that any such approvals will be obtained and/or any such conditions will be satisfied or that such sale will be consummated.

If this sale or others by AE Supply or FES are not achieved or realized, AE Supply and FES may take further substantial write-downs and impairments of assets, which could have a material adverse effect on the results of operations and financial condition of FirstEnergy and FES and put additional pressure on the success of other strategic alternatives for remaining generation assets at FES and AE Supply.

Certain FirstEnergy Companies May Not be Able to Meet Their Obligations to or on behalf of Other FirstEnergy Companies or Their Affiliates Which Could Have a Material Adverse Effect on the Results of Operations, Financial Condition or Liquidity of one or more FirstEnergy Entities, Including Additional Significant Exposure in the Event of an FES and, Possibly, FENOC Bankruptcy Proceeding

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies pursuant to transactions involving energy, coal, other commodities, services and hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, and could result in the nondefaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Certain FirstEnergy companies also provide guarantees to third party creditors on behalf of other FirstEnergy affiliate companies under transactions of the type described above or under financing transactions. Any failure to perform under such guarantee by such FirstEnergy guarantor company or under the underlying transaction by the FirstEnergy company on whose behalf the guarantee was issued could have similar adverse impacts on one or both FirstEnergy companies or their affiliates.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units, have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. If FES is called upon by NG to perform under this arrangement, FES' results of operations, financial position, and liquidity could be adversely affected, and could result in FES being unable to meet its obligations to unrelated third parties. If FE's credit support to FES for this arrangement is established as described under "Nuclear Regulation" above, FE's liquidity could also be adversely affected if such support is necessary to be utilized by FES.

In addition, there are significant commercial and other relationships among FE, FES and other FE subsidiaries, including, but not limited to, AE Supply and FENOC. These relationships include a shared services agreement, cash management, intercompany loans, tax sharing and energy-related purchases and sales, among others, which would be subject to review and possible challenge in the event of an FES bankruptcy proceeding. FirstEnergy is unable to estimate the outcome of such challenges or other claims arising out of an FES bankruptcy proceeding, any resulting material losses, obligations or other liabilities of FirstEnergy or their possible material adverse effect on the business, results of operations and financial condition of FirstEnergy, including, but not limited to, AE Supply. In the event FES seeks such protection under U.S. bankruptcy laws, FENOC may similarly seek protection under U.S. bankruptcy laws.

FES, FG, OE and TE are exposed to losses under their applicable sale and leaseback arrangements for generating facilities upon the occurrence of certain contingent events that could render those facilities worthless.

FES, FG, OE and TE have a maximum exposure to loss under those provisions of approximately $1.1 billion for FES, $199 million for OE and $154 million for TE. In addition, new and certain existing environmental requirements may force us to shut down such generating facilities or change their operating status, either temporarily or permanently, if we are unable to comply with such environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are unreasonable.

In connection with the consummation of AE Supply's pending sale of assets to Aspen, FE will provide two limited guaranties of certain obligations of AE Supply and AGC arising under the purchase agreement. The guaranties vary in amount and scope and expire in one and three years, respectively. Liabilities incurred under these guarantees could have an adverse impact on FE.

Risks Related to the CES Segment

Continued depressed prices in the wholesale energy and capacity markets may further negatively and materially impact the future results of operations and financial condition of FirstEnergy and FES and have resulted in FirstEnergy and FES conducting a strategic review of competitive operations, such as the sale or deactivation of additional generating units, which may have a further material adverse effect on the results of operations and financial condition of FirstEnergy and FES

Depressed prices in the wholesale energy and capacity markets continue to challenge the coal and nuclear baseload generating units within the CES business segment, including those of FES. The continued depression of these markets may further negatively and materially impact the future results of operations and financial condition of FirstEnergy and FES.

FE does not intend to infuse additional equity into CES and only expects to continue to support CES, including FES, as necessary to maintain safe operations and to preserve the fleet as it pursues strategic alternatives with respect to CES. However, CES has liquidity support, in the case of FES, through the secured credit facility entered into between FES and FE in December 2016 and, in the case of AE Supply, through the FirstEnergy unregulated companies' money pool. No assurance can be given, however, that such expectations will not change or that the alternatives for CES, including those discussed in "Management's Discussion and Analysis of Registrant and Subsidiaries - Executive Summary," are viable or will be achieved or sufficiently realized. If options that retain the current fleet cannot be implemented or can only be implemented for a portion of the CES fleet, we may consider other options longer term, such as the sale or deactivation of additional generating units within CES, including FES, which may have a further material adverse effect on the results of operations and financial condition of FirstEnergy and FES.

FES Has a Significant Amount of Indebtedness, Which Could Adversely Affect FirstEnergy's and FES' Cash Flow and Liquidity and the Ability of FES and its subsidiaries to Fulfill their Obligations, Which Could Cause FES to Seek Protection under U.S. Bankruptcy Laws

FES and its subsidiaries have a significant amount of indebtedness, some of which is secured. Specifically, as of December 31, 2016, $3 billion of outstanding long-term debt, of which approximately $620 million is secured and approximately $2.4 billion is unsecured.

As a result of this debt, a substantial portion of cash flow from the operations of FES must be used to make payments on this debt, including the payment of principal and interest. Furthermore, since a material percentage of the FES assets are used to secure this debt, and much of those assets have been substantially written down, there is little or no collateral available for future secured debt or credit support, which reduces FirstEnergy's and FES' flexibility in dealing with future liquidity needs or financial difficulties. This high level of indebtedness and related collateral pledges could have other adverse consequences to FES creditors, including:

- difficulty satisfying debt service and other obligations at FES and/or its individual subsidiaries;
- the inability or unwillingness to refinance debt maturities at FES subsidiaries of $130 million, $515 million, and $323 million in 2017, 2018 and 2019, respectively;
- additional postings of collateral or acceleration of payments;
- increasing the vulnerability of the business of FirstEnergy and FES to adverse industry and economic conditions;
- reducing the availability of FES cash flow to fund other corporate purposes, including the ability to pay dividends to FirstEnergy;
- limiting flexibility of FirstEnergy and FES in planning for, or reacting to, changes in their business and the industry;
- reducing the ability to enter into transactions with counterparties that may demand additional collateral or credit support from FE due to the creditworthiness;
- increasing the likelihood of litigation, the costs of which may be material;
- placing FirstEnergy and FES, at a competitive disadvantage to its competitors that are not as highly leveraged; and
- limiting, along with the financial and other restrictive covenants relating to such indebtedness, among other things, FE's and FES' ability to borrow additional funds as needed for working capital, capital expenditures and general corporate purposes and to take advantage of business opportunities as they arise or pay cash dividends.

If market conditions in the wholesale energy and capacity markets continue to be depressed and the strategy discussed in "FirstEnergy's Management's Discussion and Analysis of Financial Condition and Results of Operations" and "FES' Narrative Analysis of Results of Operations" in this Annual Report on Form 10-K for the year ended December 31, 2016 and the above risk factors are not viable, achieved or sufficiently realized, then the cash flows of FES may not be sufficient to fund debt service obligations, including the repayment at maturity all of the outstanding debt as it becomes due. In that event, FES may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms or at all to refinance its debt as it becomes due, which could have a material adverse effect on the results of operations, financial condition and liquidity of FirstEnergy and FES, result in one or more events of default being declared under various agreements related to the indebtedness of FES and cause FES to seek protection under

U.S. bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under U.S. bankruptcy laws.

Additionally, if any potential defaults at FES are not resolved through waivers or otherwise cured, lenders could accelerate the maturity of the applicable debt. These defaults would have a material adverse effect on FirstEnergy’s business, financial condition, results of operations, liquidity and the trading price of FirstEnergy securities.

Disruptions in Our Fuel Supplies and Changes in Our Fuel Transportation Needs Could Adversely Affect Our Relationships With Suppliers, Our Ability to Operate Our Generation Facilities or Lead to Business Disputes and Material Judgments Against Us, Any of Which May Adversely Impact Financial Results, and in the Case of Certain Fuel Transportation Contracts, Adverse Resolutions Could Cause FES to Seek Bankruptcy Protection and Result in One or More Events of Default Under Various Agreements Related to the Indebtedness of FES

We purchase fuel from a number of suppliers. The lack of availability of fuel at expected prices, or a disruption in the delivery of fuel which exceeds the duration of our on-site fuel inventories, including disruptions as a result of weather, increased transportation costs or other difficulties, labor relations or environmental or other regulations affecting our fuel suppliers, could cause an adverse impact on our ability to operate our facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect our results of operations.

Operation of our coal-fired generation facilities is highly dependent on our ability to procure coal. We have long-term contracts in place for a majority of our coal supply and transportation needs, one of which runs through 2028 and certain of which relate to deactivated plants. We have asserted force majeure defenses for delivery shortfalls under certain of these agreements relating to our deactivated plants. Two such agreements which are currently in separate arbitration proceedings relate to the transportation of an aggregate of a minimum of 6.0 million tons of coal annually through 2025 to certain operating and deactivated coal-fired power plants owned by FG. In addition, in one coal supply agreement, FirstEnergy, through AE Supply, has also asserted termination rights effective in 2015 and is in litigation with the counterparty.

We can provide no assurance that negotiations with counterparties, or any litigation or arbitration, will be favorably resolved. An adverse resolution of any of these material matters could have a material adverse impact on our financial condition and results of operations, and in the case of the fuel transportation contracts discussed above, such adverse resolutions could require FES to (i) restructure debt and other financial obligations, (ii) borrow additional funds from FE under its secured credit facility, (iii) sell additional assets or deactivate additional plants and/or (iv) seek protection under U.S. bankruptcy laws, which in turn would result in one or more events of default under various agreements related to the indebtedness of FES. In the event FES seeks such protection, FENOC may similarly seek protection under U.S. bankruptcy laws.

In addition, we may from time to time enter into new contracts, or renegotiate certain of these contracts, but can provide no assurance that such contracts will be negotiated or renegotiated, as the case may be, on satisfactory terms, or at all. In addition, if prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Continued Pressure on Commodity Prices Including, but Not Limited to, Fuel for our Generation Facilities, Could Adversely Affect Our Profit Margins

During the period of transition to a fully regulated company, we continue to purchase and sell electricity in the competitive retail and wholesale markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) may affect our profit margins. Competition and changes in the short or long-term market price of electricity, which are affected by changes in other commodity costs and other factors including, but not limited to, weather, energy efficiency mandates, DR initiatives and deactivations and retirements at power production facilities, may impact our results of operations and financial position by decreasing sales margins or increasing the amount we pay to purchase power to satisfy our sales obligations in the states in which we do business. We are exposed to risk from the volatility of the market price of natural gas. Our ability to sell at a profit is highly dependent on the price of natural gas. With low natural gas prices, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices, so the margins we realize from sales will be lower and, on occasion, we may curtail or cease operation of marginal plants. The availability of natural gas and issues related to its accessibility may have a long-term material impact on the price of natural gas. In addition, deterioration or weakness in the global economy has led to lower international demand for coal, oil and natural gas, which has lowered fossil fuel prices and may continue to put downward pressure on electricity prices.

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

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

We attempt to mitigate risks associated with satisfying our contractual power sales arrangements by reserving generation capacity to deliver electricity to satisfy our net firm sales contracts and, when necessary, by purchasing firm transmission service. We also routinely enter into contracts, such as fuel and power purchase and sale commitments, to hedge exposure to fuel requirements and other energy-related commodities. We may not, however, hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position could be negatively affected. In addition, these risk management related contracts could require the posting of additional collateral in the event market prices or market conditions change or our credit ratings are further downgraded.

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

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

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

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

There Are Uncertainties Relating to Our Participation in RTOs Which Could Result In Significant Additional Fees and Increased Costs to Participate in an RTO, Limit the Recovery of Costs from Retail Customers and Have an Adverse Effect on our Results of Operations and Cash Flows and Financial Condition

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

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

We incur fees and costs to participate in RTOs. Administrative costs imposed by RTOs, including the cost of administering energy markets, may increase. To the degree we incur significant additional fees and increased costs to participate in an RTO, and are limited with respect to recovery of such costs from retail customers, our results of operations and cash flows could be significantly impacted.

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

congestion and firm transmission rights that may have a financial impact on us.
As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO's market and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.
Risks Related to Business Operations Generally

We Are Subject to Risks Arising from the Operation of Our Power Plants and Transmission and Distribution Equipment Which Could Reduce Revenues, Increase Expenses and Have a Material Adverse Effect on our Business, Financial Condition and Results of Operations

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

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

Failure to Provide Safe and Reliable Service and Equipment Could Result in Serious Injury or Loss of Life That May Harm Our Business Reputation and Adversely Affect our Operating Results

We are obligated to provide safe and reliable service and equipment in our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. However, our employees, contractors and the general public may be exposed to dangerous environments, due to the nature of our operations. Failure to provide safe and reliable service and equipment due to a number of factors, including, equipment failure, accidents and weather, could result in serious injury or loss of life that may harm our business reputation and adversely affect our operating results through reduced revenues and increased capital and operating costs and the imposition of penalties/fines or other adverse regulatory outcomes.

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

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

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

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

We rely on the OTC derivative markets as part of our program to hedge the price risk associated with our power portfolio. As a qualified end-user, we are required to comply with regulatory obligations under Dodd-Frank, which includes record-keeping, reporting requirements and the clearing of some transactions that we would otherwise enter into over-the-counter and the posting of margin. Also, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swap market to decrease. These rules could impede our ability to meet our hedge targets in a cost-effective manner. FirstEnergy cannot predict the future impact Dodd-Frank rulemaking will have on its results of operations, cash flows or financial position.

Our Risk Management Policies Relating to Energy and Fuel Prices, and Counterparty Credit, Are by Their Very Nature Subject to Uncertainties, and We Could Suffer Economic Losses Resulting in an Adverse Effect on Results of Operations Despite Our Efforts to Manage and Mitigate Our Risks

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

Performance market reform. In addition, the amount of fuel required for our power plants during a given day or time period could be more than expected, which could require us to buy additional fuel at prices less favorable than the prices under our fuel contracts. As a result, actual events may lead to greater losses or costs than our risk management positions were intended to hedge.

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

The Outcome of Litigation, Arbitration, Mediation, and Similar Proceedings, Involving Our Business, or That of One or More of Our Operating Subsidiaries, Including Certain Fuel and Fuel Transportation Contracts, is Unpredictable and an Adverse Decision in Any Material Proceeding Could Have a Material Adverse Effect on Our Financial Condition and Results of Operations, and in the Case of Proceedings Related to Certain Fuel Transportation Contracts, Adverse Decisions Could Cause FES to Seek Bankruptcy Protection and Result in One or More Events of Default Under Various Agreements Related to the Indebtedness of FES

We are involved in a number of litigation, arbitration, mediation, and similar proceedings including, but not limited to, such proceedings relating to certain fuel and fuel transportation contracts as described in Note 16, Commitments, Guarantees, and Contingencies, of the Combined Notes to the Consolidated Financial Statements and further discussed above in the risk factor “Disruptions in Our Fuel Supplies and Changes in Our Fuel Transportation Needs Could Adversely Affect Our Relationships With Suppliers, Our Ability to Operate Our Generation Facilities or Lead to Business Disputes, and Material Judgments Against Us, Any of Which May Adversely Impact Financial Results, and in the Case of Certain Fuel Transportation Contracts, Adverse Resolutions Could Cause FES to Seek Bankruptcy Protection and Result in One or More Events of Default Under Various Agreements Related to the Indebtedness of FES.” These and other matters may divert financial and management resources that would otherwise be used to benefit our operations. Further, no assurances can be given that the resolution of these matters will be favorable to us. If certain matters were ultimately resolved unfavorably to us, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted, and in the case of proceedings related to certain coal transportation contracts, such unfavorable results could require FES to seek protection under U.S. bankruptcy laws, which in turn would result in one or more events of default under various agreements related to the indebtedness of FES. In the event FES seeks such protection, FENOC may similarly seek protection under U.S. bankruptcy laws.

In addition, we are sometimes subject to investigations and inquiries by various state and federal regulators due to the heavily regulated nature of our industry. Any material inquiry or investigation could potentially result in an adverse ruling against us, which could have a material adverse impact on our financial condition and operating results.

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

Approximately 55% of FirstEnergy's generation fleet capacity is coal-fired, totaling 9,406 MWs, of which 6,313 MWs is within the CES segment. Historically, coal-fired generating plants have greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to air emissions, including GHGs, and CCR disposal, than other types of electric generation facilities. In December 2014, the EPA finalized regulations for CCRs (non-hazardous waste), establishing national standards for the safe disposal of CCRs from electric generating plants. In August 2015, the EPA finalized the CPP (which has been stayed in the United States Supreme Court pending resolution of legal challenges) requiring reductions in GHG emissions from existing electric generating plants. These legal requirements and any future initiatives could impose substantial additional costs and, in the case of GHG requirements, could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements.

Capital Market Performance and Other Changes May Decrease the Value of Pension Fund Assets and Other Trust Funds, Which Could Require Significant Additional Funding and Negatively Impact our Results of Operations and Financial Condition

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our nuclear generating facilities and under pension and other postemployment benefit plans. Certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission FirstEnergy's nuclear generating facilities, to pay future pension and other obligations, requires significant judgment and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or that negatively impact the discount rate and increase the present value of liabilities may have significant impacts on the value of the decommissioning, pension and other trust funds, which could require significant additional funding and negatively impact our results of operations and financial position.

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

Owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by NERC and approved by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. NERC, RFC and FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. FERC has authority to impose penalties up to and including $1 million per day for failure to comply with these mandatory electric reliability standards.

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

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

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

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

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

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

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

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

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

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

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

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

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

We continually focus on limiting, and reducing where possible, our operation and maintenance expenses. However, we expect to continue to face increased cost pressures related to operation and maintenance expenses, including in the areas of health care and pension costs. We have experienced health care cost inflation in recent years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, discount rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. Additionally, there is an increased uncertainty related to our operation and maintenance expenses as a result of the new Trump Administration and Republican control of the U.S. Congress. While we anticipate that our operation and maintenance expenses will continue to increase, if actual results differ materially from our assumptions, our costs could be significantly higher than expected which could adversely affect our future earnings and liquidity.

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

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

Additionally, following the November 2016 United States presidential and congressional elections, U.S. and global financial markets have responded with significant volatility. FirstEnergy recognizes as a pension and other post-employment benefits (OPEB) mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement.

Cyber-Attacks, Data Security Breaches and Other Disruptions to Our Information Technology Systems Could Compromise Our Business Operations, Critical and Proprietary Information and Employee and Customer Data, Which Could Have a Material Adverse Effect on Our Business, Financial Condition and Reputation

In the ordinary course of our business, we use and are dependent upon information technology systems that utilize sophisticated operational systems and network infrastructure to run all facets of our generation, transmission and distribution services. Additionally, we store 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 secure maintenance of information and information technology systems is critical to our operations.

Over the last several years, there has been an increase in the frequency of cyber-attacks by terrorists, hackers, international activist organizations, countries and individuals. These and other unauthorized parties may attempt to gain access to our network systems or facilities, or those of third parties with whom we do business in many ways, including directly through our network infrastructure or through fraud, trickery, or other forms of deceiving our employees, contractors and temporary staff. Additionally, our information and information technology systems may be increasingly vulnerable to data security breaches, damage and/or interruption due to viruses, human error, malfeasance, faulty password management or other malfunctions and disruptions. Further, hardware, software, or applications we develop or procure from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information and/or security.

Despite security measures and safeguards we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to such attacks as a result of the rapidly evolving and increasingly sophisticated means by which attempts to defeat our security measures and gain access to our information technology systems may be made. Also, we may be at an increased risk of a cyber-attack and/or data security breach due to the nature of our business.

Any such cyber-attack, data security breach, damage, interruption and/or defect could: (i) disable our generation, transmission (including our interconnected regional transmission grid) and/or distribution services for a significant period of time; (ii) delay development and construction of new facilities or capital improvement projects; (iii) adversely affect our customer operations; (iv) corrupt data; and/or (v) result in unauthorized access to the information stored in our data centers and on our networks, including, company proprietary information, supplier information, employee data, and personal customer data, causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in economic loss and liability and harmful effects on the environment and human health, including loss of life. Additionally, because our generation, transmission and distribution services are part of an interconnected system, disruption caused by a cybersecurity incident at another utility, electric generator, RTO, or commodity supplier could also adversely affect our operations.

Although we maintain cyber insurance and property and casualty insurance, there can be no assurance that liabilities or losses we may incur will be covered under such policies or that the amount of insurance will be adequate. Further, as cyber threats become more difficult to detect and successfully defend against, there can be no assurance that we can implement adequate preventive measures, accurately assess the likelihood of a cyber-incident or quantify potential liabilities or losses. Also, we may not discover any data security breach and loss of information for a significant period of time after the data security breach occurs. For all of these reasons, any such cyber incident could result in significant lost revenue, the inability to conduct critical business functions and serve customers for a significant period of time, the use of significant management resources, legal claims or proceedings, regulatory penalties, increased regulation, increased capital costs, increased protection costs for enhanced cyber security systems or personnel, damage to our reputation and/or the rendering of our internal controls ineffective, all of which could materially adversely affect our business and financial condition.

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

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

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

Our business plan calls for execution of extensive capital investments in electric generation, transmission and distribution, including but not limited to our Energizing the Future transmission expansion program, which has been extended to include \$4.2 to \$5.8 billion in investments from 2018 through 2021. We may be exposed to the risk of substantial price increases in, or the adequacy or availability of, the costs of labor and materials used in construction, nonperformance of equipment and increased costs due to delays, including delays relating to the procurement of permits or approvals, adverse weather or environmental matters. We engage numerous contractors and enter into a large number of construction agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors' inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. Also, because we enter into construction agreements for the necessary materials and to obtain the required construction related services, any cancellation by FirstEnergy of a construction agreement could result in significant termination payments or penalties. Any delays, increased costs or losses or cancellation of a construction project could adversely affect our business and results of operations, particularly if we are not permitted to recover any such costs in rates.

Changes in Technology and Regulatory Policies May Make Our Generating Facilities Significantly Less Competitive and Adversely Affect Our Results of Operations

We primarily generate electricity at large central station generation facilities. This method results in economies of scale and lower unit costs than newer generation technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in newer generation technologies will make newer generation technologies more cost-effective, or that changes in regulatory policy will create benefits that otherwise make these newer generation technologies more competitive with central station electricity production. Increased competition, whether from such advances in technologies or from changes in regulatory policy, could result in permanent reductions in our historical load, adversely impact scheduling of generation, and decrease sales and revenues from our existing generation assets, which could have a material adverse effect on our results of operations.

Further, to the extent that newer generation technologies are connected directly to load, bypassing the transmission and distribution systems, potential impacts could include decreased transmission and distribution revenues, stranded assets and increased uncertainty in load forecasting and integrated resource planning and could adversely affect our business and results of operations.

Certain FirstEnergy Companies Have Guaranteed the Performance of Third Parties, Which May Result in Substantial Costs or the Incurrence of Additional Debt

Certain FirstEnergy companies have issued guarantees of the performance of others, which obligates such FirstEnergy companies to perform in the event that the third parties do not perform. For instance, FE is a guarantor under a syndicated senior secured term loan facility, under which Global Holding borrowed $300 million. In the event of non-performance by the third parties, FirstEnergy could incur substantial cost to fulfill this obligation and other obligations under such guarantees. Such performance guarantees could have a material adverse impact on our financial position and operating results.

Additionally, with respect to FEV's investment in Global Holding, it could require additional capital from its owners, including FEV, to fund operations and meet its obligations under its term loan facility. These capital requirements could be significant and if other partners do not fund the additional capital, resulting in FEV increasing its equity ownership and obtaining the ability to direct the significant activities of Global Holding, FEV may be required to consolidate Global Holding, increasing FirstEnergy's long-term debt by $300 million.

Energy Companies are Subject to Adverse Publicity Causing Less Favorable Regulatory and Legislative Outcomes Which Could have an Adverse Impact on Our Business

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

Risks Associated With Regulation

Any Subsequent Modifications to, Denial of, or Delay in the Effectiveness of the PUCO’s approval of the DMR could impose significant risks on FirstEnergy’s operations and Materially and Adversely Impact the Credit Ratings, Results of Operations and Financial Condition of FirstEnergy

On October 12, 2016, the PUCO denied the Ohio Companies’ modified Rider RRS and, in accordance with the PUCO Staff’s recommendation, approved a new DMR providing for the collection of $204 million annually (grossed up for income taxes) for three years with a possible extension for an additional two years. On November 10, 2016 and November 14, 2016, several parties, including the Ohio Companies, filed additional applications for rehearing on the Ohio Companies’ ESP IV with the PUCO. On December 7, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO.

Any subsequent modification to, denial of, or delay in the effectiveness of, the PUCO’s order approving the DMR could impose risks on our operations and materially and adversely impact the credit ratings, results of operations and financial condition of FirstEnergy.

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

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

On January 26, 2017, FERC Commissioner Norman Bay announced his resignation from FERC effective February 3, 2017. Commissioner Bay’s departure means there will be only two sitting commissioners on the commission; accordingly FERC will not have the FPA-required quorum of at least three commissioners to conduct commission business, including the issuance of final commission orders on pending proceedings. Delays in FERC orders could adversely impact the timing and implementation of pending or planned FERC-jurisdictional rate cases and transactions, and therefore could have a material adverse impact on our business, financial condition, results of operations and cash flow.

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

In addition, as a U.S. corporation, we are subject to U.S. laws, Executive Orders, and regulations administered and enforced by the U.S. Department of Treasury and the Department of Justice restricting or prohibiting business dealings in or with certain nations and with certain specially designated nationals (individuals and legal entities). If any of our existing or future operations or investments, including our joint venture investment in Signal Peak or our continued procurement of uranium from existing suppliers, are subsequently determined to involve such prohibited parties we could be in violation of certain covenants in our financing documents and unless we cease or modify such dealings, we could also be in violation of such U.S. laws, Executive Orders and sanctions regulations, each of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Each of the Utilities' retail rates are set by its respective regulatory agency for utilities in the state in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC through traditional, cost-based regulated utility ratemaking. As a result, any of the Utilities may not be permitted to recover its costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Factors that may affect outcomes in the distribution rate cases include: (i) the value of plant in service; (ii) authorized rate of return; (iii) capital structure (including hypothetical capital structures); (iv) depreciation rates; (v) the allocation of shared costs, including consolidated deferred income taxes and income taxes payable across the FirstEnergy utilities; (vi) regulatory approval of rate recovery mechanisms for capital spending programs (including for example accelerated deployment of smart meters); and (vii) the accuracy of forecasts used for ratemaking purposes in "future test year" cases.

FirstEnergy can provide no assurance that any base rate request filed by any of the Utilities will be granted in whole or in part. Any denial of, or delay in, any base rate request could restrict the applicable Utility from fully recovering its costs of service, may impose risks on its operations, and may negatively impact its results of operations, cash flows and financial condition. In addition, to the extent that any of the Utilities seeks rate increases after an extended period of frozen or capped rates, pressure may be exerted on the applicable legislators and regulators to take steps to control rate increases, including through some form of rate increase moderation, reduction or freeze. Any related public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues that are ultimately obtained, and the ability of the Utility to recover costs. Such uncertainty may restrict operational flexibility and resources, and reduce liquidity and increase financing costs.

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

FERC policy currently permits recovery of prudently-incurred costs associated with wholesale power rates and the expansion and updating of transmission infrastructure within its jurisdiction. If FERC were to adopt a different policy regarding recovery of transmission costs or if transmission needs do not continue or develop as projected, or if there is any resulting delay in cost recovery, our strategy of investing in transmission could be affected. If FERC were to lower the rate of return it has authorized for FirstEnergy's cost-based wholesale power rates or transmission investments and facilities, it could reduce future earnings and cash flows, and impact our financial condition.

There are multiple matters pending before FERC, including without limitation, MAIT's and JCP&L's formula rate proceedings. There can be no assurance as to the outcome of these proceedings and an adverse result could have an adverse impact on FirstEnergy’s results of operations and business conditions.

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

As a result of regulatory initiatives, changes in the electric utility business have occurred, and are continuing to take place throughout the United States, including the states in which we do business. These changes have resulted, and are expected to continue to result, in fundamental alterations in the way utilities and competitive energy providers conduct their business. FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry.

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

The Business Operations of Our Subsidiaries That Sell Wholesale Power Are Subject to Regulation by FERC and Could be Adversely Affected by Such Regulation

FERC granted the Utilities and certain FirstEnergy generating subsidiaries authority to sell electric energy, capacity and ancillary services at market-based rates. These orders also granted waivers of certain FERC accounting, record-keeping and reporting requirements, as well as, for certain of these subsidiaries, waivers of the requirements to obtain FERC approval for issuances of securities. FERC’s orders that grant this market-based rate authority reserve with FERC the right to revoke or revise that authority if FERC subsequently determines that these companies can exercise market power in transmission or generation, or create barriers to entry, or have engaged in prohibited affiliate transactions. In the event that one or more of FirstEnergy's market-based rate authorizations were to be revoked or adversely revised, the affected FirstEnergy subsidiary(ies) may be subject to sanctions and penalties, and would be required to file with FERC for authorization of individual wholesale sales transactions, which could involve costly and possibly lengthy regulatory proceedings and the loss of flexibility afforded by the waivers associated with the current market-based rate authorizations.

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

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce peak demand and energy consumption. Such conservation programs could result in load reduction and adversely impact our financial results in different ways. To the extent conservation results in reduced energy demand or significantly slows the growth in demand, the value of our competitive generation and other unregulated business activities could be adversely impacted. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery time frame in the states where we operate.

Currently, only our Ohio Companies recover lost distribution revenues that result between distribution rate cases. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We have already been adversely impacted by reduced electric usage due in part to energy conservation efforts such as the use of efficient lighting products such as CFLs, halogens and LEDs. We could also be adversely impacted if any future energy price increases result in a decrease in customer usage. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

Additionally, failure to meet regulatory or legislative requirements to reduce energy consumption or otherwise increase energy efficiency could result in penalties that could adversely affect our results.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs and Have An Adverse Effect on Our Financial Condition and Results of Operations

Where federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation does not also provide for adequate cost recovery, it could result in significant changes in our business, including material increases in REC purchase costs, purchased power costs and capital expenditures. Such mandatory renewable portfolio requirements may have an adverse effect on our financial condition and results of operations.

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

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

The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work considered by the companies to be routine maintenance. EPA has investigated alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position, but we are unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition.

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

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for, among other things, installation and operation of pollution control equipment, emissions monitoring and fees, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. We may be forced to shut down other facilities or change their operating status, either temporarily or permanently, if we are unable to comply with these or other existing or new environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are unreasonable.

For example, in December 2011, the EPA finalized MATS to establish emission standards for, among other things, mercury, PM and HCI, for electric generating units. The costs associated with MATS compliance, and other environmental laws, is substantial. As a result of a comprehensive review of FirstEnergy's coal-fired generating facilities in light of MATS and other expanded requirements, we deactivated twenty-six (26) older coal-fired generating units in 2012, 2013, and 2015.

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

At the international level, 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 has since been ratified by over 125 countries representing more than 80% of global GHG emissions and its non-binding obligations to limit global warming to well below two degrees Celsius have become effective. Further, due to the uncertainty of control technologies available to reduce GHG emissions, any other legal obligation that requires substantial reductions of GHG emissions could result in substantial additional costs, adversely affecting cash flow and profitability, and raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. It remains unclear whether and how the results of the 2016 U.S. election could impact the regulation of GHG emissions at the federal and state level.

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

Private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other relief. For example, claims have been made against certain energy companies alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. While FirstEnergy is not a party to this litigation, it, and/or one of its subsidiaries, could be named in other actions making similar allegations. An unfavorable ruling in any such case could result in the need to make modifications to our coal-fired plants or reduce emissions, suspend operations or pay money damages or penalties. Adverse rulings in these or other types of actions could have an adverse impact on our results of operations and financial condition and could significantly impact our operations.

Various Federal and State Water and Solid, Non-Hazardous and Hazardous Waste Regulations May Require Us to Make Material Capital Expenditures

In September 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 under the CWA. The EPA has also established performance standards under the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants, specifically, reducing impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) to a 12% annual average and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system) using site-specific controls based on studies to be submitted to permitting authorities. FirstEnergy is studying the cost and effectiveness of various control options to divert fish away from its plants' cooling water intake systems. Depending on the results of such studies and implementation of impingement and entrainment performance standards by permitting authorities, the future costs of compliance with these standards may require material capital expenditures.

We Are or May be Subject to Costs of Remediation of Environmental Contamination at Current or Formerly Owned Facilities

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

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

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

We have been named as a defendant in pending asbestos litigations involving multiple plaintiffs and multiple defendants, in several states. The majority of these claims arise out of alleged past exposures by contractors (and in Pennsylvania, former employees) at both currently and formerly owned electric generation plants. In addition, asbestos and other regulated substances are, and may continue to be, present at currently owned facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained and properly identified in accordance with applicable governmental regulations, including OSHA. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us. This is further complicated by the fact that many diseases, such as mesothelioma and cancer, have long latency periods in which the disease process develops, thus making it impossible to accurately predict the types and numbers of such claims in the near future. While insurance coverages exist for many of these pending asbestos litigations, others have no such coverages, resulting in FirstEnergy being responsible for all defense expenditures, as well as any settlements or verdict payouts.

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

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

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

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

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

Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Climate change could also affect the availability of a secure and economical supply of water in some locations, which is essential for continued operation of generating plants. Further, as extreme weather conditions increase system stress, we may incur costs relating to additional system backup or service interruptions, and in some instances we may be unable to recover such costs. For all of these reasons, these physical risks could have an adverse financial impact on our operations and operating results. Climate change poses other financial risks as well. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in additional system assets and purchase additional power. Additionally, decreased energy use due to weather changes may affect our financial condition through decreased rates, revenues, margins or earnings.

Future Changes in Accounting Standards May Affect Our Reported Financial Results

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

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

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

In addition, the new presidential administration of the U.S. and the majority political party of the U.S. Congress have announced a potential reform of U.S. tax laws. The details of the President's comprehensive tax plan have not yet emerged but during the presidential campaign, he outlined several proposed changes to corporate taxes. In addition, House Republicans have drafted an initial tax reform, known as the "Blueprint," to significantly amend the current income tax code. Areas of tax reform under discussion include, without limitation, the following proposals: (i) elimination (partial or full) of the deductibility of interest expense on corporate debt, (ii) reduction in the corporate federal income tax rate from 35 percent to 20 percent, and (iii) immediate expensing of capital investment expenditures.

No details regarding the transition from the current tax code to potential new tax reforms have emerged. We cannot predict whether, when or to what extent new U.S. tax laws, regulations, interpretations or rulings will be issued, nor is the long-term impact of proposed tax reform clear. A reform of U.S. tax laws may be enacted in a manner that negatively impacts our results of operations, financial condition, business operations, earnings and is adverse to FE's shareholders. Furthermore, with respect to the Utilities, FirstEnergy cannot predict what, if any, response state regulatory commissions may have if any such tax reforms are enacted and the potential response of such authorities may include imposition of rate reductions in order to pass through to customers any perceived benefit of any such tax reform.

Risks Associated With Financing and Capital Structure

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

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

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

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

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

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

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

Any Default by Customers or Other Counterparties Could Have a Material Adverse Effect on Our results of Operations and Financial Condition

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

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

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow, including our ability to pay dividends and service debt, is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. For example, reduced availability of FES cash flow resulting from a high level of indebtedness and related collateral pledges or any decision to seek protection under U.S. bankruptcy laws, could have a material adverse impact on FES' ability to pay dividends to FE. In the event FES seeks such protection under the U.S. bankruptcy laws, FENOC may similarly seek protection under U.S. bankruptcy laws. Any inability of our subsidiaries to pay dividends or make cash payments to us may adversely affect our cash flows and financial condition.

Additionally, our utility and transmission subsidiaries are regulated by various state utility and federal commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state and federal commissions could attempt to impose restrictions on the ability of our utility and transmission subsidiaries to pay dividends or otherwise restrict cash payments to us.

FE May Issue Additional Equity Securities, Which Would Likely Lead to Dilution of Its Issued and Outstanding Common Stock and May Materially and Adversely Affect the Price of FE's Common Stock

As part of its capital program, FE expects to issue $500 million of equity in each year 2017 through 2019 to help meet long-term cash needs, including cash requirements to fund Regulated Transmission's Energizing the Future program and for other general corporate and business purposes. The issuance of additional shares of FE's previously authorized and unissued common stock would likely result in the dilution of the ownership interests of FE's existing shareholders and a large issuance of additional shares may negatively impact the market price of FE's common stock. FE is authorized to issue 490 million shares of common stock. As of December 31, 2016, 442,344,218 shares of FE's common stock were issued and outstanding, and there were outstanding options and restricted stock awards totaling an additional 1,529,167 shares of FE's common stock. FE also has additional shares available for grant under the FirstEnergy Corp. 2015 Incentive Compensation Plan and equity compensation plans or amendments to existing equity compensation plans for employees and directors may be adopted from time to time. Issuance of these shares of common stock would likely dilute the ownership interests of FE's then existing shareholders.

Because FE's decision to issue additional equity securities in any future offering will depend on market conditions and other factors beyond FE's control, it cannot predict or estimate the amount, timing or nature of FE's future issuances, if any, and/or otherwise predict the extent of any future dilution.

We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts They May be Paid

Our Board of Directors will continue to regularly evaluate our common stock dividend and determine an appropriate dividend each quarter taking into account such factors as, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

The Recognition of Impairments of Goodwill and Long-Lived Assets Has Adversely Effected Our Results of Operations and Additional Impairments in the CES Segment Could Result Under Certain Circumstances In One or More Events of Default Under Various Agreements Related to the Indebtedness of FE and Have a Material Adverse

Effect on FirstEnergy’s Business, Financial Condition, Results of Operations, Liquidity and the Trading Price of FirstEnergy's Securities

We have approximately $5.6 billion of goodwill on our consolidated balance sheet as of December 31, 2016. Goodwill is tested for impairment annually as of July 31 or whenever events or changes in circumstances indicate impairment may have occurred. Key assumptions incorporated in the estimated cash flows used for the impairment analysis requiring significant management judgment include: discount rates, growth rates, future energy and capacity pricing, projected operating income, changes in working capital, projected capital expenditures, projected funding of pension plans, expected results of future rate proceedings, the impact of pending carbon and other environmental legislation and terminal multiples. For example, as a result of low capacity prices associated with the 2019/2020 PJM Base Residual Auction in May 2016, as well as its annual update to its fundamental long-term capacity and energy price forecast in the second quarter of 2016, FirstEnergy determined that an interim impairment analysis of the goodwill at

CES was necessary in connection with the preparation of its financial statements for the three-month period ended June 30, 2016. Based on such impairment analysis, FirstEnergy’s second quarter 2016 results included a pre-tax non-cash impairment charge of approximately $800 million, representing the total goodwill at the CES segment, including $23 million at FES.

In addition, we also review our long-lived assets and investments for impairment when circumstances indicate the carrying value of these assets may not be recoverable. For example, in 2016, we recorded a $647 million non-cash pre-tax impairment charge associated with exit operations of Bay Shore Unit 1 and W.H. Sammis, Units 1-4, including $517 million at FES. In connection with the intention to exit competitive generation, FirstEnergy recognized in the fourth quarter of 2016 a non-cash pre-tax impairment charge of approximately $9.2 billion ($8.1 billion - FES) in FirstEnergy’s 2016 consolidated statement of income.

We are unable to predict whether further impairments of one or more of our long-lived assets or investments may occur in the future. The actual timing and amounts of any impairments to goodwill, or long-lived assets in the future depends on many factors, including the outcome of the strategic review, interest rates, sector market performance, our capital structure, natural gas or other commodity prices, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable acquisitions, environmental regulations and other factors. A determination that goodwill, a long-lived asset, or other investments are impaired would result in a non-cash charge that could materially adversely affect our results of operations and capitalization. Additionally, although the recent amendment to FE’s credit facility revised the debt to total capitalization ratio covenant to exclude non-cash after-tax charges of up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and each of their subsidiaries, charges beyond that amount could result in an event of default related to the indebtedness of FE and have a material adverse effect on FirstEnergy’s business, financial condition, results of operations, liquidity and the trading price of FirstEnergy's securities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The first mortgage indentures for the Ohio Companies, Penn, MP, PE, WP, FG and NG constitute direct first liens on substantially all of the respective physical property, subject only to excepted encumbrances, as defined in the first mortgage indentures. See "Note 7, Leases", and "Note 12, Capitalization", of the Combined Notes to Consolidated Financial Statements for information concerning leases and financing encumbrances affecting certain of the Utilities', FG's and NG's properties.

FirstEnergy controls the following generation sources as of February 21, 2017, shown in the table below. Except for the leasehold interests, OVEC participation and wind and solar power arrangements referenced in the footnotes to the table, substantially all of FES' competitive generating units are owned by NG (nuclear) and FG (non-nuclear); the regulated generating units are owned by JCP&L and MP.

			Competitive		
Plant (Location)	Unit	Total	FES	AE Supply	Regulated
		Net Demonstrated Capacity (MW)			
Super-critical Coal-fired:					
Bruce Mansfield (Shippingport, PA)	1	830 (1)	830	—	—
Bruce Mansfield (Shippingport, PA)	2	830	830	—	—
Bruce Mansfield (Shippingport, PA)	3	830	830	—	—
Harrison (Haywood, WV)	1-3	1,984	—	—	1,984
Pleasants (Willow Island, WV)	1-2	1,300	—	1,300	—
W. H. Sammis (Stratton, OH)	6-7	1,200	1,200	—	—
Fort Martin (Maidsville, WV)	1-2	1,098	—	—	1,098
		8,072	3,690	1,300	3,082
Sub-critical and Other Coal-fired:					
W. H. Sammis (Stratton, OH)	1-5	1,010	1,010	—	—
Bay Shore (Toledo, OH)	1	136	136	—	—
OVEC (Cheshire, OH) (Madison, IN)	1-11	188 (3)	110	67	11
		1,334	1,256	67	11
Nuclear:					
Beaver Valley (Shippingport, PA)	1	939	939	—	—
Beaver Valley (Shippingport, PA)	2	933 (4)	933	—	—
Davis-Besse (Oak Harbor, OH)	1	908	908	—	—
Perry (N. Perry Village, OH)	1	1,268	1,268	—	—
		4,048	4,048	—	—
Gas/Oil-fired:					
AE Nos. 1, 2, 3, 4 & 5 (Springdale, PA)	1-5	638 (2)	—	638	—
West Lorain (Lorain, OH)	1-6	545	545	—	—
AE Nos. 12 & 13 (Chambersburg, PA)	12-13	88 (2)	—	88	—
AE Nos. 8 & 9 (Gans, PA)	8-9	88 (2)	—	88	—
Forked River (Ocean County, NJ)	2	86	86	—	—
Hunlock CT (Hunlock Creek, PA)	1	45 (2)	—	45	—
Buchanan (Oakwood, VA)	1-2	43 (5)	—	43	—
Other		59	59	—	—

		1,592		690	902	—
Pumped-storage Hydro:						
Bath County (Warm Springs, VA)	1-6	1,200	(6)	—	713	(2) 487
Yard's Creek (Blairstown Twp., NJ)	1-3	210	(7)	—	—	210
		1,410		—	713	697
Wind and Solar Power		496	(8)	496	—	—
Total		16,952		10,180	2,982	3,790

(1) Includes FE's leasehold interest of 93.83% (779 MWs) from non-affiliates.
(2) Subject to an asset purchase agreement with Aspen, as disclosed in Note 22, Subsequent Events.
(3) Represents FES' 4.85%, AE Supply's 3.01% and MP's 0.49% entitlement based on their participation in OVEC.
(4) Includes OE's leasehold interest of 2.60% (24 MWs) from non-affiliates of which FES purchases all the output pursuant to full output cost-of-service PSAs.
(5) Represents Buchanan Energy's 50% interest. Buchanan Energy is a subsidiary of AE Supply.
(6) Represents AGC's 40% interest in Bath County. The station is operated by VEPCO. AGC is 59% owned by AE Supply and 41% owned by MP.
(7) Represents JCP&L's 50% ownership interest.
(8) Includes 167 MWs from leased facilities and 329 MWs under power purchase agreements.

The above generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. FirstEnergy's overhead and underground transmission lines aggregate 24,551 circuit miles.

The Utilities' electric distribution systems include 272,763 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of approximately 160,259,826 kV-amperes.

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

FirstEnergy's distribution and transmission systems as of December 31, 2016, consist of the following:

	Distribution Lines[1]	Transmission Lines[1]	Substation Transformer Capacity[2] kV Amperes
OE	67,066	377	7,644,893
Penn	13,570	—	1,090,120
CEI	33,448	—	10,696,730
TE	19,024	73	2,992,453
JCP&L	23,414	2,655	22,833,721
ME	18,897	1,497	10,953,095
PN	27,554	2,761	15,730,203
ATSI[3]	—	7,789	36,096,629
WP	21,918	4,338	16,030,166
MP	22,185	2,667	12,030,702
PE	25,687	2,142	11,260,514
TrAIL	—	252	12,900,600
Total	272,763	24,551	160,259,826

(1) Circuit Miles

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

(3) Represents transmission line assets of 69 kV and greater located in the service territories of OE, Penn, CEI and TE.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

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

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

FirstEnergy had no transactions regarding purchases of FE common stock during the fourth quarter of 2016.

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

ITEM 6. SELECTED FINANCIAL DATA

FirstEnergy

For the Years Ended December 31,	2016	2015	2014	2013	2012
	(In millions, except per share amounts)				
Revenues	$14,562	$15,026	$15,049	$14,892	$15,255
Income (Loss) From Continuing Operations	$(6,177)	$578	$213	$375	$755
Earnings (Loss) Available to FirstEnergy Corp.	$(6,177)	$578	$299	$392	$770
Earnings (Loss) per Share of Common Stock:					
Basic - Continuing Operations	$(14.49)	$1.37	$0.51	$0.90	$1.81
Basic - Discontinued Operations (Note 20)	—	—	0.20	0.04	0.04
Basic - Earnings (Loss) Available to FirstEnergy Corp.	$(14.49)	$1.37	$0.71	$0.94	$1.85
Diluted - Continuing Operations	$(14.49)	$1.37	$0.51	$0.90	$1.80
Diluted - Discontinued Operations (Note 20)	—	—	0.20	0.04	0.04
Diluted - Earnings (Loss) Available to FirstEnergy Corp.	$(14.49)	$1.37	$0.71	$0.94	$1.84
Weighted Average Shares Outstanding:					
Basic	426	422	420	418	418
Diluted	426	424	421	419	419
Dividends Declared per Share of Common Stock	$1.44	$1.44	$1.44	$1.65	$2.20
Total Assets[(1)]	$43,148	$52,094	$51,552	$49,980	$50,110
Capitalization as of December 31:					
Total Equity	$6,241	$12,422	$12,422	$12,695	$13,093
Long-Term Debt and Other Long-Term Obligations	18,192	19,099	19,080	15,753	15,114
Total Capitalization	$24,433	$31,521	$31,502	$28,448	$28,207

[(1)]Reflects the retrospective application of 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 retrospective change decreased Total Assets as of December 31 as follows: 2015 - $93 million, 2014 - $96 million, 2013 - $78 million, 2012 - $65 million, as these amounts were reclassified from deferred charges and other assets to long-term debt and other long-term obligations.

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.

	2016		2015	
	High	Low	High	Low
First Quarter	$36.54	$30.62	$41.68	$33.82
Second Quarter	$36.32	$31.37	$37.05	$32.46
Third Quarter	$36.60	$32.12	$35.09	$30.31
Fourth Quarter	$34.83	$29.33	$33.00	$28.89
Yearly	$36.60	$29.33	$41.68	$28.89

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

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SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2011 in FE'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 85,173 and 85,172 holders of 442,344,218 and 442,477,633 shares of FE's common stock as of December 31, 2016 and January 31, 2017, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12, Capitalization of the Combined Notes to Consolidated Financial Statements.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "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 ability to experience growth in the Regulated Distribution and Regulated Transmission segments.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including, but not limited to, our planned forward-looking formula rates 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 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.
- The risks and uncertainties associated with the lack of viable alternative strategies regarding the CES segment, thereby causing FES, and possibly FENOC, to restructure its debt and other financial obligations with its creditors or seek protection under U.S. bankruptcy laws and the losses, liabilities and claims arising from such bankruptcy proceeding, including any obligations at FirstEnergy.
- The risks and uncertainties at the CES segment, including FES and its subsidiaries and FENOC, related to continued depressed wholesale energy and capacity markets, and the viability and/or success of strategic business alternatives, such as potential CES generating unit asset sales, the potential conversion of the remaining generation fleet from competitive operations to a regulated or regulated-like construct or the potential need to deactivate additional generating units.
- The substantial uncertainty as to FES’ ability to continue as a going concern and substantial risk that it may be necessary for FES, and possibly FENOC, to seek protection under U.S. bankruptcy laws.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments, such as long-term fuel and transportation agreements.
- The uncertainties associated with the deactivation of older regulated and competitive units, including the impact on vendor commitments, such as long-term fuel and transportation agreements, 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.
- 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.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Replacement power costs being higher than anticipated or not fully hedged.
-

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.

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- 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).
- 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.
- 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.
- 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 labor disruptions by our unionized workforce.
- 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 impact of the regulatory process and resulting outcomes on the 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 Ohio DMR.
- 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; 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.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- 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.
- 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.
- 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 significant accounting policies.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- 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.
- Further 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, increase requirements to post additional collateral to support, or accelerate payments under outstanding commodity positions, LOCs and other financial guarantees, and the impact of these events on the financial condition and liquidity of FirstEnergy and/or its subsidiaries, specifically the subsidiaries within the CES segment.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

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

These forward-looking statements are also qualified by, and should be read together with, the risk factors included in (a) Item 1A. Risk Factors, (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 the registrants. 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 CORP.
MANAGEMENT’S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS
FIRSTENERGY’S BUSINESS

FirstEnergy and its subsidiaries are principally involved in the generation, transmission and distribution of electricity. Its reportable segments are as follows: Regulated Distribution, Regulated Transmission, and CES.

During the fourth quarter of 2016, FirstEnergy modified its segment reporting to reclassify the results of operations from certain transmission assets of ME, PN and JCP&L, from the Regulated Distribution segment to the Regulated Transmission segment. Costs associated with these transmission assets, which are currently included in ME, PN, and JCP&L's stated rates, will be recovered through MAIT's and JCP&L’s formula rates prospectively, once approved by FERC. 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 2015 and 2014 have been revised to conform to the current presentation reflecting the operating activity of the identified transmission assets within Regulated Transmission.

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 controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

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	1,045
Penn	Western Pennsylvania	165
CEI	Northeastern Ohio	750
TE	Northwestern Ohio	310
JCP&L	Northern, Western and East Central New Jersey	1,117
ME	Eastern Pennsylvania	565
PN	Western Pennsylvania	588
WP	Southwest, South Central and Northern Pennsylvania	724
MP	Northern, Central and Southeastern West Virginia	390
PE	Western Maryland and Eastern West Virginia	404
		6,058

[1] As of December 31, 2016

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI and 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 forward-looking rates at ATSI and TrAIL, as well as stated transmission rates at certain of FirstEnergy's utilities. As discussed in "FERC Matters" below, effective January 31, 2017, MAIT includes the transmission assets of ME and PN, and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. Those applications are pending before FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under the forward-looking rates, each of ATSI's and TrAIL's revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. Except for the recovery of the PATH abandoned project regulatory asset, the segment's revenues are primarily from transmission services provided to LSEs pursuant to the PJM Tariff. 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. As of December 31, 2016, this business segment controlled 13,162 MWs of electric generating capacity, including, as further discussed below, 1,572 MWs of natural gas and hydroelectric generating capacity subject to an asset purchase agreement with Aspen and the 1,300 MW Pleasants power station which was offered into MP's RFP process by AE Supply. The CES segment’s operating results are 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, as well as other operating and maintenance costs, including costs incurred by FENOC.

Corporate support not charged to FE's subsidiaries, interest expense on stand-alone holding company debt, corporate income taxes and other businesses that do not constitute an operating segment 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, 2016, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $2.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

FirstEnergy believes having a combination of distribution, transmission and generation assets in a regulated or regulated-like construct is the best way to serve customers. FirstEnergy's strategy is to be a fully regulated utility, focusing on stable and predictable earnings and cash flow from its regulated business units.

Over the past several years, CES has been impacted by a prolonged decrease in demand and excess generation supply in the PJM Region, which has resulted in a period of protracted low power and capacity prices. To address this, CES sold or deactivated more than 6,770 MWs of competitive generation from 2012 to 2015. Additionally, CES has continued to focus on cost reductions, including those identified as part of FirstEnergy's previously disclosed cash flow improvement plan.

However, the energy and capacity markets continue to be weak, as evidenced by the significantly depressed capacity prices from the 2019/2020 PJM Base Residual Auction in May of 2016 as well as the current forward pricing and the long-term fundamental view on energy and capacity prices, which resulted in a non-cash pre-tax impairment charge of $800 million ($23 million at FES) recognized in the second quarter of 2016 representing the total amount of goodwill at CES.

As part of a continual process to evaluate its overall generation business, on July 22, 2016, FirstEnergy announced its intent to exit the 136 MW Bay Shore Unit 1 generating station by October 2020 and to deactivate Units 1-4 of the W.H. Sammis generating station totaling 720 MWs by May 2020, resulting in a $647 million ($517 million at FES) non-cash pre-tax impairment charge in the second quarter of 2016. Furthermore, in November of 2016, FirstEnergy announced that it had begun a strategic review of its competitive operations as it transitions to a fully regulated utility with a target to implement its exit from competitive operations by mid-2018.

As a result of this strategic review, FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement to sell four of AE Supply's natural gas generating plants and approximately 59% of AGC's interest in Bath County (1,572 MWs of combined capacity) for an all cash purchase price of $925 million, subject to customary and other closing conditions as further discussed below under "Competitive Generation Asset Sale", including the satisfaction and discharge of $305 million of AE Supply's senior notes, which is expected to require the payment of a "make-whole" premium currently estimated to be approximately $100 million based on current interest rates. Additionally, in connection with MP's RFP seeking additional generation capacity, AE Supply offered the Pleasants power station (1,300 MWs) for approximately $195 million. A winning bidder is expected to be announced in connection with the filing of appropriate applications for approval of the transactions with the WVPSC and FERC.

Although FirstEnergy is targeting mid-2018 to exit from competitive operations, the options for the remaining portion of CES' generation are still uncertain, but could include one or more of the following:

- Legislative or regulatory solutions for generation assets that recognize their environmental or energy security benefits,
- Additional asset sales and/or plant deactivations,
- Restructuring FES debt with its creditors, and/or
- Seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

Furthermore, adverse outcomes in previously disclosed disputes regarding long-term coal transportation contracts and/or the inability to extend or refinance debt maturities at FES subsidiaries, could accelerate management's targeted timeline and limit its options to exit competitive operations to either restructuring debt with its creditors or seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

As part of assessing the viability of strategic alternatives, FirstEnergy determined that the carrying value of long-lived assets of the competitive business were not recoverable, specifically given FirstEnergy’s target to implement its exit from competitive operations by mid-2018, significantly before the end of their original useful lives, and the anticipated cash flows over this shortened period. As a result, CES recorded a non-cash pre-tax impairment charge of $9,218 million ($8,082 million at FES) in the fourth quarter of 2016 to reduce the carrying value of certain assets to their estimated fair value, including long-lived assets such as generating plants and nuclear fuel, as well as other assets such as materials and supplies.

Today, the competitive generation portfolio is comprised of more than 13,000 MWs of generation, primarily from coal, nuclear and natural gas and oil fuel sources. The assets can generate approximately 70-75 million MWHs annually, with up to an additional five million MWHs available from purchased power agreements for wind, solar, and CES' entitlement in OVEC, of which a portion is sold through various retail channels and the remainder targeting forward wholesale or spot sales. Subject to the completion of the sale of the AE Supply natural gas generating plants and AGC’s interest in Bath County and, if accepted in the MP RFP process as the winning bidder, the transfer of the Pleasants Power station to MP, the size and generation capacity of CES’ current portfolio will reduce to approximately 10,000 MWs with approximately 60-65 million MWHs produced annually.

The competitive business continues to be managed conservatively due to the stress of weak energy prices, insufficient results from recent capacity auctions and anemic demand forecasts that have lowered the value of the business. Furthermore, the credit quality of CES, specifically FES' unsecured debt rating of Caa1 at Moody’s, CCC+ at S&P and C at Fitch and negative outlook from each of the rating agencies has challenged its ability to hedge generation with retail and forward wholesale sales due to collateral requirements that otherwise would reduce available liquidity. A lack of viable alternative strategies for its competitive portfolio has and would further stress the financial condition of FES. As a result, CES' contract sales are expected to decline from 53 million MWHs in 2016 to 40-45 million MWHs in 2017 and to 35-40 million MWHs in 2018. While the reduced contract sales will decrease potential collateral requirements, market price volatility may significantly impact CES' financial results due to the increased exposure to the wholesale spot market.

As previously disclosed, FES has $130 million of debt maturities that need to be refinanced in 2017 (and $515 million of maturing debt in 2018 beginning in the second quarter). Based on its current senior unsecured debt rating and current capital structure, reflecting the impact of the impairment charges discussed above, as well as the forecasted decline in wholesale forward market prices over the next few years, these debt maturities will be difficult to refinance, even on a secured basis, which would further stress FES' anticipated liquidity. Furthermore, lack of clarity regarding the timing and viability of alternative strategies, including additional asset sales or deactivations and/or converting generation from competitive operations to a regulated or regulated-like construct in a way that provides FES with the means to satisfy its obligations over the long-term, may require FES to restructure debt and other financial obligations with its creditors or seek protection under U.S bankruptcy laws. In the event FES seeks protection under U.S. bankruptcy laws, FENOC may similarly seek such protection. Although management is exploring capital and other cost reductions, asset sales, and other options to improve cash flow as well as continuing with legislative efforts to explore a regulatory solution, these obligations and their impact on liquidity raise substantial doubt about FES’ ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern.

As FirstEnergy continues to evaluate and implement the strategic review for its competitive operations, management continues to focus on its two regulated businesses - Regulated Transmission and Regulated Distribution - which focus on delivering enhanced customer service and reliability, strengthening grid and cyber-security and adding resiliency and operating flexibility to the transmission and distribution infrastructure as well as improving the reliability and efficiency of Regulated Distribution's generation capacity - all while delivering solid results.

Together, the Regulated Transmission and Distribution businesses provide stable, predictable earnings and cash flows to support FE’s dividend. These regulated businesses are expected to provide 4%−6% compounded annual earnings growth from 2016 to 2019, which increases to 7%−9% with the inclusion of the DMR in Ohio which was implemented on January 1, 2017 to support investment in modernization of the Ohio Companies' distribution systems.

With more than 24,000 miles in operations, the transmission system is the centerpiece of FirstEnergy’s regulated investment strategy. Rate base is expected to grow 9% over the next five years as the company plans to invest $4.2 to $5.8 billion in capital from 2017 to 2021 as part of its Energizing the Future transmission plan, which began as a $4.2 billion investment plan from 2014 through 2017 to upgrade FirstEnergy's transmission system.

These investments continue to be focused in the stand-alone transmission companies with effective and proposed forward-looking formula rates including ATSI, TrAIL, MAIT (which include the transmission assets of ME and PN, effective January 31, 2017), and JCP&L. Filings were made with FERC on October 28, 2016 to implement and transition to a forward-looking formula rate for MAIT's and JCP&L's transmission investments. FirstEnergy believes its existing transmission infrastructure creates incremental investment opportunities of approximately $20 billion beyond those identified through 2021 which will make the transmission system more reliable, robust, secure and resistant to extreme weather events, with improved operational flexibility. FirstEnergy plans to fund a portion of these investments with $500 million of equity annually from 2017 through 2019.

In addition to the significant opportunities at Regulated Transmission, the scale and diversity of the ten Utilities that comprise the Regulated Distribution segment uniquely position this business unit for growth and represents an additional investment opportunity. In 2016, eight of the ten Utilities completed rate proceedings which will provide benefits to the customers and communities those Utilities serve while providing for additional growth opportunities, such as future investments in smart meter technology and electric system improvement projects to increase reliability and improve service to their customers as well as exploring future opportunities in customer engagement that focuses on the electrification of customers' homes and businesses by providing a full range of products and services.

Although weather adjusted distribution deliveries through 2019 are forecasted to be flat as compared to 2016, Regulated Distribution’s earnings over the next three years are anticipated to increase as a result of (i) the PUCO-approved ESP IV, which includes $204 million in additional annual revenue pursuant to DMR which became effective January 1, 2017, (ii) the PAPUC-approved settlement agreements in the Pennsylvania Companies’ base rate cases, which include approximately $290 million in aggregate additional annual revenue, effective January 27, 2017, and (iii) the NJBPU-approved settlement in JCP&L’s base rate case, which provides for an $80 million annual revenue increase effective January 1, 2017.

Planned capital expenditures for Regulated Distribution are approximately $1.3 billion, annually for 2017 through 2019.

FINANCIAL OVERVIEW

	For the Years Ended December 31			Increase (Decrease)			
(In millions, except per share amounts)	2016	2015	2014	2016 vs 2015		2015 vs 2014	
REVENUES:	$14,562	$15,026	$15,049	$(464)	(3)%	$(23)	— %
OPERATING EXPENSES:							
Fuel	1,666	1,855	2,280	(189)	(10)%	(425)	(19)%
Purchased power	3,813	4,318	4,716	(505)	(12)%	(398)	(8)%
Other operating expenses	3,858	3,749	3,962	109	3 %	(213)	(5)%
Pension and OPEB mark-to-market adjustment	147	242	835	(95)	(39)%	(593)	(71)%
Provision for depreciation	1,313	1,282	1,220	31	2 %	62	5 %
Amortization of regulatory assets, net	320	268	12	52	19 %	256	NM
General taxes	1,042	978	962	64	7 %	16	2 %
Impairment of assets	10,665	42	—	10,623	NM	42	NM
Total operating expenses	22,824	12,734	13,987	10,090	79 %	(1,253)	(9)%
OPERATING INCOME (LOSS)	(8,262)	2,292	1,062	(10,554)	NM	1,230	NM
OTHER INCOME (EXPENSE):							
Investment income (loss)	84	(22)	72	106	NM	(94)	NM
Impairment of equity method investment	—	(362)	—	362	(100)%	(362)	NM
Interest expense	(1,157)	(1,132)	(1,081)	(25)	2 %	(51)	5 %
Capitalized financing costs	103	117	118	(14)	(12)%	(1)	(1)%
Total other expense	(970)	(1,399)	(891)	429	(31)%	(508)	57 %
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(9,232)	893	171	(10,125)	NM	722	NM
INCOME TAXES (BENEFITS)	(3,055)	315	(42)	(3,370)	NM	357	NM
INCOME (LOSS) FROM CONTINUING OPERATIONS	(6,177)	578	213	(6,755)	NM	365	NM
Discontinued operations (net of income taxes of $69)	—	—	86	—	— %	(86)	(100)%
NET INCOME (LOSS)	$(6,177)	$578	$299	$(6,755)	NM	$279	93 %
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:							
Basic - Continuing Operations	$(14.49)	$1.37	$0.51	$(15.86)	NM	$0.86	NM
Basic - Discontinued Operations	—	—	0.20	—	— %	(0.20)	(100)%
Basic - Net Income (Loss)	$(14.49)	$1.37	$0.71	$(15.86)	NM	$0.66	93 %
Diluted - Continuing Operations	$(14.49)	$1.37	$0.51	$(15.86)	NM	$0.86	NM

Diluted - Discontinued Operations	—	—	0.20	—	—	%	(0.20)	(100)%
Diluted - Net Income (Loss)	$(14.49)	$1.37	$0.71	$(15.86)	NM		$0.66	93 %

NM - Not Meaningful

FirstEnergy’s net loss in 2016 was $(6,177) million, or a basic and diluted loss of $(14.49) per share of common stock, compared with net income of $578 million, or basic and diluted earnings of $1.37 per share of common stock in 2015, and $299 million, or basic and diluted earnings of $0.71 per share of common stock in 2014. Highlights of the key changes in year-over-year financial results are included below:

2016 compared with 2015

FirstEnergy's operating results in 2016 decreased $6,755 million as compared to 2015, primarily reflecting pre-tax impairment charges of $10,665 million recognized in 2016, as discussed in the "Executive Summary" above, including the following:

- The impairment of $800 million of goodwill at CES in the second quarter of 2016, reflecting a weak outlook for energy and capacity markets.
- Impairment charges totaling $647 million in the second quarter of 2016 resulting from management's decision to exit the Bay Shore Unit 1 generating station and Units 1-4 of the W.H. Sammis generating station.
- Impairment charges of $9,218 million resulting from management's plans to exit competitive operations by mid-2018 and the anticipated cash flows over this shortened period.

Additionally, the Company recognized valuation allowances against state and local NOL carryforwards of $168 million as further discussed below.

FirstEnergy’s 2016 revenues decreased $464 million as compared to the same period in 2015, resulting from a $835 million decrease at CES, partially offset by an increases of $47 million and $97 million at Regulated Distribution and Regulated Transmission, respectively.

- The decrease in revenue at CES resulted from a 15 million MWH decline in contract sales, as the segment continues to align sales to its generation, as well as lower capacity revenue associated with lower capacity auction prices. The decline in contract sales volume was partially offset by higher wholesale sales and higher net gains on financially settled contracts.
- The increase in revenue at Regulated Transmission primarily reflect recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by adjustments associated with ATSI and TrAIL's annual rate filing for costs previously recovered as well as a lower ROE in 2016 at ATSI under its FERC-approved comprehensive settlement related to the implementation of its forward-looking rate.
- The increase in revenue at Regulated Distribution primarily resulted from higher weather-related distribution deliveries and the full year impact of net rate increases implemented in 2015, partially offset by lower generation sales. Distribution deliveries increased 0.3%, or 0.4 million MWHs, reflecting higher weather-related sales partially offset by the impact of lower weather-adjusted average customer usage reflecting the impact of more energy efficient products and services.

Operating expenses increased $10,090 million in 2016 as compared to 2015, reflecting increases at CES of $9,799 million, primarily associated with the asset impairment charges discussed above, and Regulated Transmission of $77 million, partially offset by a decrease of $50 million at Regulated Distribution.

Changes in certain operating expenses include the following:

- Purchased power decreased $505 million mainly due to lower volumes at CES and Regulated Distribution and lower capacity expense at CES.
- Fuel expense decreased $189 million mainly resulting from lower generation at CES associated with outages and lower economic dispatch of fossil units reflecting low wholesale spot market energy prices, as well as lower unit prices on fossil fuel contracts.
- Pension and OPEB mark-to-market adjustments decreased $95 million to $147 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate used to measure benefit obligations partially offset by higher than expected asset returns and changes in certain actuarial assumptions.
- Other operating expenses increased $109 million, primarily reflecting an increase at Regulated Distribution resulting from the recognition of economic development and energy efficiency obligations in accordance with the PUCO's order approving the Ohio Companies' ESP IV, higher network transmission expenses, which are recovered through transmission rates, higher retirement benefit costs, and higher operating and maintenance expenses associated with storm restoration costs, partially offset by lower PJM transmission costs and lower nuclear planned outage costs at CES.

Other expense decreased $429 million, primarily due to the absence of a $362 million pre-tax impairment charge associated with FEV's investment in Global Holding recognized in 2015 and lower OTTI on NDT investments.

FirstEnergy’s 2016 effective tax rate was 33.1% on pre-tax losses as compared to 35.3% on pre-tax income in 2015. The change primarily relates to the $800 million impairment of goodwill, of which $433 million was non-deductible for tax purposes. Additionally, $168 million of valuation allowances were recorded against state and local NOL carryforwards and $78 million of valuation allowances were recorded against state and local property deferred tax assets, that management believes, more likely than not, will not be realized.

2015 compared with 2014

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, $155 million at Regulated Distribution and $73 million at Regulated Transmission.

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 $528 million increase at Regulated Distribution and a $237 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 to align sales to its generation, 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 generation revenue. Distribution deliveries decreased 0.8%, or 1.1 million MWHs, as weather adjusted sales declined as a result of energy efficiency products and services 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 its 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 $257 million and $71 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 costs and retail-related costs partially offset by higher nuclear planned outage costs. Regulated Distribution other operating expenses increased $163 million resulting from higher network transmission expenses, which are recovered through transmission rates, 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 on NDT investments, 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 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 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.

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 19, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

During the fourth quarter of 2016, FirstEnergy modified its segment reporting to reclassify the results of operations from certain transmission assets of ME, PN and JCP&L, from the Regulated Distribution segment to the Regulated Transmission segment. Costs associated with these transmission assets, which are currently included in ME, PN, and JCP&L's stated rates, will be recovered through MAIT's and JCP&L’s formula rates prospectively, once approved by FERC. 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 2015 and 2014 have been revised to conform to the current presentation reflecting the operating activity of the identified transmission assets within Regulated Transmission.

Net income (loss) by business segment was as follows:

				Increase (Decrease)	
	2016	2015	2014	2016 vs 2015	2015 vs 2014
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$651	$588	$433	$63	$155
Regulated Transmission	331	328	255	3	73
Competitive Energy Services	(6,919)	89	(331)	(7,008)	420
Corporate/Other [1]	(240)	(427)	(58)	187	(369)
Net Income (Loss)	$(6,177)	$578	$299	$(6,755)	$279
Basic Earnings (Losses) Per Share:					
Continuing operations	$(14.49)	$1.37	$0.51	$(15.86)	$0.86
Discontinued operations	—	—	0.20	—	(0.20)
Earnings (loss) per basic share	$(14.49)	$1.37	$0.71	$(15.86)	$0.66
Diluted Earnings (Losses) Per Share:					
Continuing operations	$(14.49)	$1.37	$0.51	$(15.86)	$0.86
Discontinued operations	—	—	0.20	—	(0.20)
Earnings (loss) per diluted share	$(14.49)	$1.37	$0.71	$(15.86)	$0.66

[1] Includes Corporate support costs not charged to FE's subsidiaries 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.

Summary of Results of Operations — 2016 Compared with 2015

Financial results for FirstEnergy's business segments in 2016 and 2015 were as follows:

2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,401	$ 1,151	$ 3,892	$ (181)	$ 14,263
Other	228	—	178	(107)	299
Internal	—	—	479	(479)	—
Total Revenues	9,629	1,151	4,549	(767)	14,562
Operating Expenses:					
Fuel	567	—	1,099	—	1,666
Purchased power	3,273	—	1,019	(479)	3,813
Other operating expenses	2,436	161	1,526	(265)	3,858
Pension and OPEB mark-to-market adjustment	101	1	45	—	147
Provision for depreciation	676	187	387	63	1,313
Amortization of regulatory assets, net	313	7	—	—	320
General taxes	720	153	134	35	1,042
Impairment of assets	—	—	10,665	—	10,665
Total Operating Expenses	8,086	509	14,875	(646)	22,824
Operating Income (Loss)	1,543	642	(10,326)	(121)	(8,262)
Other Income (Expense):					
Investment income	49	—	66	(31)	84
Impairment of equity method investment	—	—	—	—	—
Interest expense	(586)	(158)	(194)	(219)	(1,157)
Capitalized financing costs	20	34	37	12	103
Total Other Expense	(517)	(124)	(91)	(238)	(970)
Income (Loss) Before Income Taxes (Benefits)	1,026	518	(10,417)	(359)	(9,232)
Income taxes (benefits)	375	187	(3,498)	(119)	(3,055)
Net Income (Loss)	$651	$ 331	$ (6,919)	$ (240)	$ (6,177)

2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,386	$ 1,054	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,582	1,054	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	2,240	156	1,670	(317)	3,749
Pension and OPEB mark-to-market adjustment	179	3	60	—	242
Provision for depreciation	664	164	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of assets	8	—	34	—	42
Total Operating Expenses	8,136	432	5,076	(910)	12,734
Operating Income	1,446	622	308	(84)	2,292
Other Income (Expense):					
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(600)	(147)	(192)	(193)	(1,132)
Capitalized financing costs	25	44	39	9	117
Total Other Expense	(533)	(103)	(169)	(594)	(1,399)
Income Before Income Taxes	913	519	139	(678)	893
Income taxes	325	191	50	(251)	315
Net Income	$588	$ 328	$ 89	$ (427)	$ 578

Changes Between 2016 and 2015 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$15	$ 97	$ (601)	$ (8)	$ (497)
Other	32	—	(27)	28	33
Internal	—	—	(207)	207	—
Total Revenues	47	97	(835)	227	(464)
Operating Expenses:					
Fuel	34	—	(223)	—	(189)
Purchased power	(275)	—	(437)	207	(505)
Other operating expenses	196	5	(144)	52	109
Pension and OPEB mark-to-market adjustment	(78)	(2)	(15)	—	(95)
Provision for depreciation	12	23	(7)	3	31
Amortization of regulatory assets, net	52	—	—	—	52
General taxes	17	51	(6)	2	64
Impairment of assets	(8)	—	10,631	—	10,623
Total Operating Expenses	(50)	77	9,799	264	10,090
Operating Income (Loss)	97	20	(10,634)	(37)	(10,554)
Other Income (Expense):					
Investment income	7	—	82	17	106
Impairment of equity method investment	—	—	—	362	362
Interest expense	14	(11)	(2)	(26)	(25)
Capitalized financing costs	(5)	(10)	(2)	3	(14)
Total Other Expense	16	(21)	78	356	429
Income (Loss) Before Income Taxes (Benefits)	113	(1)	(10,556)	319	(10,125)
Income taxes (benefits)	50	(4)	(3,548)	132	(3,370)
Net Income (Loss)	$63	$ 3	$ (7,008)	$ 187	$ (6,755)

Regulated Distribution — 2016 Compared with 2015

Regulated Distribution's net income increased $63 million in 2016 compared to 2015, including a $78 million decrease in its Pension and OPEB mark-to-market adjustment, partially offset by regulatory charges of $51 million resulting from the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV. Excluding the impact of these adjustments, year-over-year earnings reflect higher distribution deliveries and the full year impact of net rate increases implemented in 2015 as a result of approved rate cases at certain of the Utilities, as further described below, partially offset by higher retirement benefit costs and other operating expenses.

Revenues —

The $47 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In millions)		
Distribution services	$4,785	$4,510	$ 275
Generation sales:			
Retail	4,119	4,303	(184)
Wholesale	497	573	(76)
Total generation sales	4,616	4,876	(260)
Other	228	196	32
Total Revenues	$9,629	$9,582	$ 47

Distribution services revenues increased $275 million primarily resulting from the full year impact of approved base distribution rate increases at the Pennsylvania Companies, effective May 3, 2015, and 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 revenues were impacted by higher rates associated with the recovery of deferred costs as well as higher weather-related 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 2016	2015	Increase (Decrease)
	(In thousands)		
Residential	54,840	54,466	0.7 %
Commercial	43,340	43,091	0.6 %
Industrial	50,082	50,269	(0.4)%
Other	579	585	(1.0)%
Total Electric Distribution MWH Deliveries	148,841	148,411	0.3 %

Higher distribution deliveries to residential and commercial customers reflect increased weather-related usage resulting from cooling degree days that were 18% above 2015, and 37% above normal, partially offset by heating degree days that were 6% below 2015, and 9% below normal. Additionally, distribution deliveries to residential and commercial customers were impacted by declining average customer usage associated with more energy efficient products and services. Year-to-date deliveries to industrial customers declined slightly as the increase from shale customer usage was more than offset by a decrease from steel and chemical customer usage.

The following table summarizes the price and volume factors contributing to the $260 million decrease in generation revenues in 2016, as compared to 2015:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$ (196)
Change in prices	12
	(184)
Wholesale:	
Effect of increase in sales volumes	47
Change in prices	(107)
Capacity revenue	(16)
	(76)
Decrease in Generation Revenues	$ (260)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania, and New Jersey. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 83% from 80% for the Ohio Companies, to 67% from 65% for the Pennsylvania Companies and to 51% from 50% for JCP&L. The increase in retail generation prices primarily resulted from an ENEC rate increase in West Virginia, effective January 1, 2016, partially offset by lower default service auction prices in Ohio and Pennsylvania.

Wholesale generation revenues decreased $76 million in 2016 compared to the same period of 2015, primarily due to lower spot market energy prices, partially offset by higher wholesale sales. The difference between current wholesale generation revenues and certain energy costs incurred is deferred for future recovery or refund, with no material impact to earnings.

Other revenues increased $32 million, primarily related to a $29 million gain on the sale of oil and gas rights at WP.

Operating Expenses —

Total operating expenses decreased $50 million primarily due to the following:

- Fuel expense increased $34 million in 2016, as compared to the same period of 2015, primarily related to higher generation.

- Purchased power costs decreased $275 million in 2016, as compared to the same period of 2015, primarily due to lower volumes resulting from increased customer shopping, as described above, as well as lower unit costs reflecting lower default service auction prices in Ohio and Pennsylvania.

Source of Change in Purchased Power	Increase(Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (133)
Change due to decreased volumes	(6)

	(139)
Purchases from affiliates:	
Change due to decreased unit costs	(2)
Change due to decreased volumes	(204)
	(206)
Capacity expense	(5)
Amortization of deferred costs	75
Decrease in Purchased Power Costs	$ (275)

- Other operating expenses increased $196 million primarily due to:
    - An increase of $51 million resulting from the recognition of economic development and energy efficiency obligations in accordance with the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.
- Higher retirement benefit costs of $57 million.
- Higher transmission expenses of $56 million primarily related to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The difference between current revenues and transmission costs incurred are deferred for future recovery or refund, resulting in no material impact on current period earnings.
- Higher operating and maintenance expense of $33 million, primarily due to increased storm restoration costs, which are deferred for future recovery resulting in no material impact on current period earnings.

- Pension and OPEB mark-to-market adjustments decreased $78 million to $101 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate used to measure benefit obligations partially offset by higher than expected asset returns and changes in certain actuarial assumptions.

- Depreciation expenses increased $12 million due to a higher asset base.

- Net amortization of regulatory assets increased $52 million primarily due to:
- A full year recovery of storm costs in New Jersey, Pennsylvania, and West Virginia, effective with the implementation of new rates as discussed above ($35 million),
- Recovery of West Virginia vegetation management program costs ($40 million), partially offset by
- Higher deferral of storm restoration costs ($39 million).

- General taxes increased $17 million primarily due to higher revenue-related taxes in Pennsylvania and higher property taxes in Ohio.

Other Expense —

Total other expense decreased $16 million primarily related to lower interest expense resulting from various debt maturities at JCP&L and OE in 2016.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.5% and 35.6% for 2016 and 2015, respectively.

Regulated Transmission — 2016 Compared with 2015

Net income increased $3 million in 2016 compared to 2015, primarily resulting from a higher rate base, partially offset by adjustments associated with ATSI and TrAIL's annual rate filing for costs previously recovered, a lower return on equity at ATSI, and lower capitalized financing costs.

Revenues —

Total revenues increased $97 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by adjustments associated with ATSI's and TrAIL's annual rate filing for costs previously recovered as well as a lower ROE at ATSI under its FERC-approved comprehensive settlement related to the implementation of its forward-looking rate effective January 1, 2015.

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

Revenues by Transmission Asset Owner	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In millions)		
ATSI	$540	$446	$ 94
TrAIL	252	252	—
PATH	12	13	(1)
Utilities	347	343	4
Total Revenues	$1,151	$1,054	$ 97

Operating Expenses —

Total operating expenses increased $77 million principally due to higher property taxes and depreciation expense at ATSI, which are recovered through ATSI's forward-looking formula rate.

Other Expenses —
Other expense increased $21 million in 2016, as compared to 2015, primarily due to lower capitalized financing costs resulting from lower construction work in progress balances at ATSI as well as increased interest expense resulting from a long-term debt issuance of $150 million at ATSI in the fourth quarter of 2015, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.1% and 36.8% for 2016 and 2015, respectively.
CES — 2016 Compared with 2015

Operating results decreased $7,008 million in 2016 compared to 2015, primarily resulting from pre-tax asset impairment charges of $10,665 million discussed above, partially offset by lower mark-to-market gains on commodity contract positions, a lower Pension and OPEB mark-to-market adjustment and lower settlement and termination costs related to coal contracts. Excluding these items, year-over-year operating results were impacted by lower capacity revenues, lower sales volumes, a termination charge associated with an FES customer contract, and higher retirement and employee benefit costs, partially offset by lower fuel costs, reduced transmission expenses, and lower purchased power.

Revenues —

Total revenues decreased $835 million in 2016, as compared to 2015, primarily due to decreased sales volumes and lower capacity revenue, partially offset by higher net gains on financially settled contracts and an increase in short-term (net hourly position) transactions, 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 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$812	$1,269	$ (457)
Governmental Aggregation	814	1,012	(198)
Mass Market	169	265	(96)
POLR	583	712	(129)
Structured Sales	463	558	(95)
Total Contract Sales	2,841	3,816	(975)
Wholesale	1,457	1,225	232
Transmission	73	138	(65)
Other	178	205	(27)
Total Revenues	$4,549	$5,384	$ (835)

MWH Sales by Channel	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	15,310	23,585	(35.1)%
Governmental Aggregation	13,730	15,443	(11.1)%
Mass Market	2,431	3,878	(37.3)%
POLR	9,969	11,950	(16.6)%
Structured Sales	11,414	12,902	(11.5)%
Total Contract Sales	52,854	67,758	(22.0)%
Wholesale	15,201	7,326	107.5 %
Total MWH Sales	68,055	75,084	(9.4)%

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

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(445)	$(12)	$ —	$ —	$(457)
Governmental Aggregation	(112)	(86)	—	—	(198)
Mass Market	(99)	3	—	—	(96)
POLR	(118)	(11)	—	—	(129)
Structured Sales	(64)	(31)	—	—	(95)
Wholesale	223	(10)	98	(79)	232

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflects the continuation of FES' strategy to more effectively hedge its generation, as discussed above. The Direct, Governmental Aggregation, and Mass Market customer base was 1.1 million as of December 31, 2016, compared to 1.6 million as of December 31, 2015. Although unit pricing was lower year-over-year in the Direct and Governmental Aggregation channels, the decrease was primarily attributable to lower capacity expenses, as discussed below, which is a component of the retail price.

The decrease in POLR sales of $129 million was primarily due to lower volumes. Structured Sales decreased $95 million, primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues increased $232 million, primarily due to an increase in short-term (net hourly position) transactions and higher net gains on financially settled contracts, partially offset by a decrease in capacity revenue from lower capacity auction prices and lower spot market energy prices.

Transmission revenue decreased $65 million, primarily due to lower congestion revenue associated with less volatile market conditions.

Other revenue decreased $27 million, primarily due to the absence of a gain on the sale of property to a regulated affiliate in 2015 and lower lease revenues from the expiration of a nuclear sale-leaseback agreement.

Operating Expenses —

Total operating expenses increased $9,799 million in 2016 due to the following:

- Fuel costs decreased $223 million, primarily due to lower generation associated with outages and lower economic dispatch of fossil units resulting from low wholesale spot market energy prices, as discussed above, as well as lower unit prices on fossil fuel contracts. Additionally, fuel costs were impacted by lower settlement and termination costs on coal contracts. The impact of settlements and terminations of coal contracts resulted in a pre-tax loss of $58 million and $67 million in 2016 and 2015, respectively.

- Purchased power costs decreased $437 million due to lower capacity expenses ($234 million) and lower volumes ($203 million). The decrease in capacity expense, which is a component of CES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with CES' retail sales obligations. Lower volumes primarily resulted from lower contract sales, as discussed above, partially offset by higher economic purchases, resulting from the low wholesale spot market price environment.

- Fossil operating costs increased $4 million, primarily due to increased outage costs and higher employee benefit costs, partially offset by lower operating costs from the deactivation of certain fossil plants in April 2015.
- Nuclear operating costs decreased $39 million, primarily as a result of lower refueling outage costs, partially offset by higher employee benefit costs. There were two refueling outages in 2016 as compared to three refueling outages in 2015.
- Retirement benefit costs increased $31 million.
- Transmission expenses decreased $175 million, primarily due to lower congestion and market-based ancillary costs associated with less volatile market conditions as compared to 2015, as well as lower load requirements.
- Other operating expenses increased $35 million, primarily due to lower mark-to-market gains on commodity contract positions of $84 million and a $37 million charge associated with the termination of an FES customer contract, partially offset by lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement.
- Pension and OPEB mark-to-market adjustments decreased $15 million to $45 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate used to measure benefit obligations, partially offset by higher than expected asset returns and changes in other actuarial assumptions.
- Depreciation expense decreased $7 million, primarily as a result of an out-of-period adjustment to reduce depreciation of a hydroelectric generating station, partially offset by a higher asset base.
- General taxes decreased $6 million, primarily due to lower gross receipts taxes associated with lower retail sales volumes.
- Impairment of assets increased $10,631 million, primarily due to impairments of goodwill and the competitive generation assets discussed above.

Other Expense —

Total other expense decreased $78 million in 2016 compared to 2015 primarily due to lower OTTI on NDT investments.

Income Taxes (Benefits) —

CES' effective tax rate was 33.6% on pre-tax losses and 36.0% on pre-tax income for 2016 and 2015, respectively. The change in the effective tax rate is primarily due to $168 million of valuation allowances recorded against state and local NOL carryforwards and $78 million of valuation allowances recorded against state and local property deferred tax assets, that management believes, more likely than not, will not be realized, as well as the impairment of $800 million of goodwill, of which $433 million is non-deductible for tax purposes.

Corporate/Other — 2016 Compared with 2015

Financial results and reconciling items included in Corporate/Other resulted in a $187 million increase in net income in 2016 compared to 2015 primarily due to the absence of a $362 million pre-tax impairment of FirstEnergy's equity method investment in Global Holding recognized in 2015. Excluding the impact of this adjustment, year-over-year results were impacted by higher operating and maintenance costs, higher interest expense and changes in the consolidated effective tax rate, which for 2016 was 33.1% on pre-tax losses and for 2015 was 35.5% on pre-tax income. The increased interest expense primarily relates to debt redemption costs related to the FE revolving credit facility and term loans, as discussed in "Capital Resources and Liquidity". The higher consolidated effective tax rate primarily resulted from the absence of tax benefits recognized in 2015 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, as well as from changes in state apportionment factors.

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	$9,386	$ 1,054	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,582	1,054	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	2,240	156	1,670	(317)	3,749
Pension and OPEB mark-to-market adjustment	179	3	60	—	242
Provision for depreciation	664	164	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of assets	8	—	34	—	42
Total Operating Expenses	8,136	432	5,076	(910)	12,734
Operating Income	1,446	622	308	(84)	2,292
Other Income (Expense):					
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(600)	(147)	(192)	(193)	(1,132)
Capitalized interest	25	44	39	9	117
Total Other Expense	(533)	(103)	(169)	(594)	(1,399)
Income From Continuing Operations Before Income Taxes	913	519	139	(678)	893
Income taxes	325	191	50	(251)	315
Income From Continuing Operations	588	328	89	(427)	578
Discontinued Operations, net of tax	—	—	—	—	—
Net Income	$588	$ 328	$ 89	$ (427)	$ 578

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2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$8,850	$ 817	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,054	817	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	2,077	143	2,075	(333)	3,962
Pension and OPEB mark-to-market adjustment	506	2	327	—	835
Provision for depreciation	651	134	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	692	71	171	28	962
Impairment of assets	—	—	—	—	—
Total Operating Expenses	7,879	361	6,823	(1,076)	13,987
Operating Income (Loss)	1,175	456	(534)	(35)	1,062
Other Income (Expense):					
Investment income	56	—	54	(38)	72
Impairment of equity method investment	—	—	—	—	—
Interest expense	(603)	(117)	(197)	(164)	(1,081)
Capitalized interest	14	55	37	12	118
Total Other Expense	(533)	(62)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	642	394	(640)	(225)	171
Income taxes (benefits)	209	139	(223)	(167)	(42)
Income (Loss) From Continuing Operations	433	255	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$433	$ 255	$ (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	$536	$ 237	$ (788)	$ 20	$ 5
Other	(8)	—	16	(36)	(28)
Internal	—	—	(133)	133	—
Total Revenues	528	237	(905)	117	(23)
Operating Expenses:					
Fuel	(34)	—	(391)	—	(425)
Purchased power	163	—	(694)	133	(398)
Other operating expenses	163	13	(405)	16	(213)
Pension and OPEB mark-to-market adjustment	(327)	1	(267)	—	(593)
Provision for depreciation	13	30	7	12	62
Amortization of regulatory assets, net	260	(4)	—	—	256
General taxes	11	31	(31)	5	16
Impairment of assets	8	—	34	—	42
Total Operating Expenses	257	71	(1,747)	166	(1,253)
Operating Income	271	166	842	(49)	1,230
Other Income (Expense):					
Investment loss	(14)	—	(70)	(10)	(94)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	3	(30)	5	(29)	(51)
Capitalized interest	11	(11)	2	(3)	(1)
Total Other Expense	—	(41)	(63)	(404)	(508)
Income From Continuing Operations Before Income Taxes	271	125	779	(453)	722
Income taxes	116	52	273	(84)	357
Income From Continuing Operations	155	73	506	(369)	365
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income	$155	$ 73	$ 420	$ (369)	$ 279

Regulated Distribution — 2015 Compared with 2014

Regulated Distribution's net income increased $155 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 of the Utilities.

Revenues —

The $528 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	$4,510	$4,056	$ 454
Generation sales:			
Retail	4,303	4,043	260
Wholesale	573	751	(178)
Total generation sales	4,876	4,794	82
Other	196	204	(8)
Total Revenues	$9,582	$9,054	$ 528

Distribution services revenues increased $454 million primarily resulting from approved base distribution rate increases at the Pennsylvania Companies, effective May 3, 2015, and at 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 revenues were impacted by higher rates associated with the recovery of deferred costs, as well as higher weather-related usage, as described below. 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 products and services 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 average customer usage similar to the impact to residential customers. 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 $82 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	(151)
Change in prices	(82)
Capacity revenue	55
	(178)
Increase in Generation Revenues	$ 82

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 prices.

Wholesale generation revenue decreased $178 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.

Operating Expenses —

Total operating expenses increased $257 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 prices, and higher capacity expense at MP, partially offset by lower volumes 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 $163 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.

- Higher distribution operating and maintenance expenses of $61 million, reflecting increased reliability maintenance and other employee benefit costs, partially offset by lower storm restoration costs.

- Pension and OPEB mark-to-market adjustments 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 $13 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 $11 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 32.6% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and tax benefits recognized in 2014.

Regulated Transmission — 2015 Compared with 2014

Net income increased $73 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 $237 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 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:

Revenues by Transmission Asset Owner	For the Years Ended December 31 2015	2014	Increase (Decrease)
	(In millions)		
ATSI	$446	$242	$ 204
TrAIL	252	214	38
PATH	13	13	—
Utilities	343	348	(5)
Total Revenues	$1,054	$817	$ 237

Operating Expenses —

Total operating expenses increased $71 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 36.8% and 35.3% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and 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. 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	NM
Total MWH Sales	75,084	99,556	(24.6)%

NM - Not Meaningful

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

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(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 reflecting FES' strategy to more effectively hedge its generation as discussed above. 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 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 capacity auctions, 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 a gain on the sale of property to a regulated affiliate in 2015 and 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 refueling outage costs and higher employee benefit expenses. There were three refueling outages in 2015 as compared to two refueling 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 lower retail sales volumes.
- Pension and OPEB mark-to-market adjustments 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 $216 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.
- Impairment of assets were $34 million in 2015 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 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 Tax (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 and reconciling items included in 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 FE's $1 billion term loan entered into in March 2014 and the absence of a gain on the termination of interest rate swaps 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.
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, 2016 and December 31, 2015, and the changes during the year ended December 31, 2016:

Regulatory Assets (Liabilities) by Source	December 31, 2016	December 31, 2015	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$90	$ 185	$ (95)
Customer receivables for future income taxes	444	355	89
Nuclear decommissioning and spent fuel disposal costs	(304)	(272)	(32)
Asset removal costs	(470)	(372)	(98)
Deferred transmission costs	127	115	12
Deferred generation costs	215	243	(28)
Deferred distribution costs	296	335	(39)
Contract valuations	153	186	(33)
Storm-related costs	353	403	(50)
Other	110	170	(60)
Net Regulatory Assets included on the Consolidated Balance Sheets	$1,014	$ 1,348	$ (334)

Regulatory assets that do not earn a current return totaled approximately $153 million and $148 million as of December 31, 2016 and 2015, respectively, primarily related to storm damage costs, and are currently being recovered through rates.

As of December 31, 2016 and December 31, 2015, FirstEnergy had approximately $157 million and $116 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’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.

FE, and its utility and transmission subsidiaries, expect their existing sources of liquidity to remain sufficient to meet their respective anticipated obligations. In addition to internal sources to fund liquidity and capital requirements for 2017 and beyond, FE and its utility and transmission subsidiaries expect 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, including cash requirements to fund Regulated Transmission's capital program, may be met through a combination of an additional $500 million of equity in each year 2017 through 2019, and new long-term debt, in each case, subject to market conditions and other factors. FirstEnergy also expects to issue long-term debt at certain Utilities to, among other things, refinance short-term and maturing long-term debt, subject to market conditions and other factors.

FirstEnergy’s unregulated subsidiaries, specifically FES and AE Supply, expect to rely on, in the case of AE Supply, internal sources, the unregulated companies' money pool, and proceeds generated from previously disclosed asset sales, subject to closing, and with respect to FES, a two-year secured line of credit with FE of up to $500 million, as further described below. Additionally, FES subsidiaries have debt maturities in 2017 and 2018 of $130 million and $515 million, respectively. The inability to refinance such debt maturities could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under its credit facility with FE, (iii) further asset sales or plant deactivations, and/or (iv) seek protection under U.S. bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under U.S. bankruptcy laws.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016.

Capital expenditures for 2016 and anticipated expenditures for 2017 and 2018 by reportable segment are included below:

Reportable Segment	2016 Actual[(1]	2016 Pension/OPEB Mark-to-Market Capital Costs	2016 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2017 Forecast[(2)]	2018 Forecast[(2)]
	(In millions)				
Regulated Distribution	$1,327	$ 46	$ 1,281	$ 1,325	$ 1,305
Regulated Transmission[(4)]	1,005	4	1,001	1,000	1,000
CES[(3)]	547	(3)	550	365	290
Corporate/Other	93	—	93	95	90
Total	$2,972	$ 47	$ 2,925	$ 2,785	$ 2,685

(1) Includes an increase of approximately $47 million related to the capital component of the pension and OPEB mark-to-market adjustment.
(2) Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.

(3) Approximately $35 million and $20 million of forecasted annual capital expenditures are associated with the Pleasants power station for 2017 and 2018, respectively. On February 3, 2017, AE Supply offered the Pleasants power station into MP's RFP, as discussed above.
(4) 2018 Forecast represents the mid-point of Regulated Transmission's 2018 forecasted capital expenditures of $800 million to $1,200 million.

Capital expenditures for 2016 and anticipated expenditures for 2017 by subsidiary are included in the following table (anticipated capital expenditures by subsidiary for 2018 are not finalized):

Operating Company	2016 Actual[1]	2016 Pension/OPEB Mark-to-Market Capital Costs	2016 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2017 Forecast[2]
	(In millions)			
OE	$163	$ 7	$ 156	$ 145
Penn	50	3	47	45
CEI	158	25	133	125
TE	46	2	44	45
JCP&L	399	17	382	350
ME	139	6	133	135
PN	184	1	183	160
MP	242	(6)	248	250
PE	103	(5)	108	125
WP	166	—	166	205
ATSI	487	—	487	420
TrAIL	217	—	217	60
FES	470	(3)	473	320
AE Supply[3]	63	—	63	45
MAIT	—	—	—	260
Other subsidiaries	85	—	85	95
Total	$2,972	$ 47	$ 2,925	$ 2,785

(1) Includes an increase of approximately $47 million related to the capital component of the pension and OPEB mark-to-market adjustment.
(2) Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.
(3) Approximately $35 million of forecasted annual capital expenditures are associated with the Pleasants power station for 2017. On February 3, 2017, AE Supply offered the Pleasants power station into MP's RFP, as discussed above.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the Energizing the Future transmission plan, which FirstEnergy plans to invest $4.2 to $5.8 billion in capital investments from 2017 to 2021, and began as a $4.2 billion investment plan from 2014 through 2017 to upgrade 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 2016, FirstEnergy's capital expenditures under this plan were $3.4 billion. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2021.

Additionally, planned capital expenditures in 2019 for Regulated Distribution are approximately $1.3 billion primarily to enhance the Utilities' distribution systems.

In alignment with FirstEnergy’s strategy to invest in its Regulated Transmission and Regulated Distribution segments as it transitions to a fully regulated company, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile and maintaining investment grade ratings at its regulated businesses and FE.

Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

Any financing plans by FE or any of its subsidiaries, including the issuance of equity and debt, and the refinancing of short-term and maturing long-term debt are subject to market conditions and other factors, such as the impact of the current energy and capacity markets and potential credit rating changes. No assurance can be given that any such issuances, financing or refinancing, as the case may be, will be completed as anticipated or at all. Any delay in the completion of financing plans could require FE or any of its subsidiaries to utilize short-term borrowing capacity, which could impact available liquidity. In particular, FES may borrow under its credit facility with FE, to the extent available, to refinance debt maturities and mandatory purchase obligations, which would impact available liquidity for FES and, FE to the extent it funds any such borrowings through its facility and/or cash. In addition, FE and its subsidiaries expect to continually evaluate any planned financings, which may result in changes from time to time.

As of December 31, 2016, 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, 2016, included the following:

Currently Payable Long-Term Debt	(In millions)
FMBs	$ 725
Unsecured notes	680
Unsecured PCRBs	158
Collateralized lease obligation bonds	5
Sinking fund requirements	74
Other notes	43
	$ 1,685

Short-Term Borrowings / Revolving Credit Facilities

On December 6, 2016, FE and certain subsidiaries entered into new five-year syndicated credit facilities available through December 6, 2021, and concurrently terminated existing syndicated credit facilities that were to expire March 31, 2019, as follows:

- FE and the Utilities entered into a new $4 billion revolving credit facility, which represents an increase of $500 million over the existing $3.5 billion facility it replaced,
- FET and its subsidiaries entered into a $1 billion revolving credit facility, which replaced their existing $1 billion facility, and
- FES and AE Supply terminated their unsecured $1.5 billion credit facility (commitments of $900 million and $600 million for FES and AE Supply, respectively) and FES entered into a new, two-year secured credit facility with FE in which FE provided a committed line of credit to FES of up to $500 million and additional credit support of up to $200 million to cover a $169 million surety bond for the benefit of the PA DEP with respect to LBR, and other bonds as designated in writing to FE. In connection with the cancellation of the prior FES/AE Supply facility and entry into the new FES secured facility with FE, certain commitments and amendments associated with shared services and operational matters were made including, without limitation, as follows: (i) FE reaffirmed its obligations under the Intercompany Tax Allocation Agreement, and (ii) amendments to the Service Agreement by and among FESC, FES, FG and NG, to prevent termination until the earlier of December 31, 2018, or a change in control of FES or its subsidiaries.

FE, the Utilities and FET and its subsidiaries may use borrowings under their new facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. FES expects to use its new facility with FE to conduct its ordinary course of business in lieu of borrowing under the unregulated money pool. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million).

Under the terms of the new FE and FET credit facilities, each borrower is required to maintain a consolidated debt to total capitalization ratio, as defined, of no more than 0.65 to 1.00, or in the case of FET, 0.75 to 1.00. For purposes of calculating its ratio, FE is permitted certain adjustments to total capitalization including (i) an exclusion for certain previously incurred after-tax, non-cash write-downs and non-cash charges of approximately $2.75 billion and (ii) a new exclusion for additional after-tax, non-cash write-downs and non-cash charges up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and each of their subsidiaries. Additionally, under the new credit facility, FE is now also required to maintain a minimum interest coverage ratio of

1.75 to 1.00 until December 31, 2017, 2.00 to 1.00 beginning January 1, 2018 until December 31, 2018, 2.25 to 1.00 beginning January 1, 2019 until December 31, 2019, and 2.50 to 1.00 beginning January 1, 2020 until December 31, 2021. FE and each of the other borrowers under the new FE and FET credit facilities are currently in compliance with these financial covenants. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 described above are excluded from FE's calculation of total capitalization pursuant to the new $5.5 billion after-tax exclusion referenced in (ii) above consistent with the terms of the facility. Other terms of the new FE credit facility exclude FES and AE Supply from the definition of “significant subsidiaries,” which removes them from FE’s covenants and defaults resulting from adverse judgments in excess of $100 million and eliminates lender approvals previously required for FES and AE Supply asset sales.

Outstanding alternate base rate advances under the new FE and FET facilities will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to the applicable borrower’s then-current senior unsecured non-credit enhanced debt ratings (reference ratings) plus the highest of (i) the “prime rate” published by the Wall Street Journal from time to time, (ii) the sum of 1/2 of 1% per annum plus the federal funds rate in effect from time to time and (iii) the LIBOR for a one-month interest period plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to the applicable borrower’s reference ratings. Swing line loans under the new FE facility will bear interest at a rate per annum equal to the sum of the alternate base rate plus an applicable margin determined by reference to the applicable borrower’s reference ratings. Changes in reference ratings of a borrower would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

FirstEnergy had $2,675 million and $1,708 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FirstEnergy’s available liquidity from external sources as of January 31, 2017 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2021	$4,000	$ 1,341
FET[2]	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 2,341
		Cash	—	308
		Total	$5,000	$ 2,649

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

FES had $101 million (payable to AE Supply) and $8 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FES' available liquidity as of January 31, 2017 was as follows:

Type	Commitment	Available Liquidity
	(In millions)	
Two-year secured credit facility with FE	$ 500	$ 500
Cash	—	2
	$ 500	$ 502

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, 2016:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)		
FE	$4,000	$ —	$ — (1)
FET	—	1,000	— (1)
OE	500	—	500 (2)
CEI	500	—	500 (2)
TE	500	—	500 (2)
JCP&L	600	—	500 (2)
ME	300	—	500 (2)
PN	300	—	300 (2)
WP	200	—	200 (2)
MP	500	—	500 (2)

PE	150	—	150	(2)
ATSI	—	500	500	(2)
Penn	50	—	100	(2)
TrAIL	—	400	400	(2)
MAIT	—	400	400	(2)(3)

(1) No limitations.
(2) Includes amounts which may be borrowed under the regulated companies' money pool.
(3) Pending regulatory approval, as discussed under "Outlook - FERC Matters" below.

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, 2016, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants as well as in the case of FE, the minimum interest coverage ratio requirement, in each case as defined under the respective facilities. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 disclosed above are excluded from FE's calculation of total capitalization pursuant to the new exclusion referenced in (ii) above consistent with the terms of the facility.

Term Loans

On December 6, 2016, FE terminated its existing $1 billion and $200 million term loan credit agreements and entered into a new $1.2 billion five-year syndicated term loan credit agreement. The term loan contains covenants and other terms and conditions substantially similar to those of the FE revolving credit facility described above, including a consolidated debt to total capitalization ratio and minimum interest coverage ratio requirement.

The initial borrowing under the new $1.2 billion FE 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. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE’s reference ratings plus the highest of (i) the administrative agent’s publicly-announced “prime rate”, (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE’s reference ratings. Changes in FE’s reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

On February 16, 2017, FE entered into two separate $125 million three-year term loan credit agreements with Bank of America, N.A. and The Bank of Nova Scotia, respectively, the proceeds of which were used to reduce short-term debt. The terms and conditions of these new credit agreements are substantially similar to the December 6, 2016, $1.2 billion five-year syndicated term loan credit agreement.

As of December 31, 2016, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants as well as the interest coverage ratio requirement, as defined under its term loan.

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 2016 was 0.69% per annum for the regulated companies’ money pool and 2.02% per annum for the unregulated companies’ money pool.

As discussed above, FES expects to use its new $500 million secured credit facility with FE in lieu of borrowing under the unregulated companies' money pool. In addition, a separate money pool for use by FES, its subsidiaries and FENOC is expected to be established in the first quarter of 2017 at which time those companies will no longer have access to the unregulated companies' money pool. As of January 31, 2017, FES, its subsidiaries and FENOC had no borrowings in the aggregate under the unregulated companies' money pool.

Pollution Control Revenue Bonds

In 2016, as discussed below, FG remarketed $86 million of fixed rate PCRBs and retired $12 million of variable interest rate PCRBs, which resulted in the elimination of LOCs related to $92 million of variable interest rate PCRBs that are no longer outstanding.

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 January 31, 2017:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FE	—	—	—	BB+	Baa3	BBB-
FES	B	B1	—	CCC+	Caa1	C
AE Supply	BB	—	BB	BB-	B1	BB-
AGC	—	—	—	BB-	Baa3	BB
ATSI	—	—	—	BBB-	Baa2	BBB+
CEI	BBB+	Baa1	A-	BBB-	Baa3	BBB+
FET	—	—	—	BB+	Baa3	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	Baa1	BBB+
MP	BBB+	A3	BBB+	—	—	—
OE	BBB+	A2	A-	BBB-	Baa1	BBB+
PN	—	—	—	BBB-	Baa2	BBB+
Penn	—	A2	A-	—	—	—
PE	BBB+	A3	BBB+	—	—	—
TE	BBB+	Baa1	A-	—	—	—
TrAIL	—	—	—	BBB-	A3	BBB+
WP	BBB+	A2	A-	—	—	—

In January 2017, Fitch initiated coverage of FE's subsidiaries and established ratings as indicated in the above table.

On February 3, 2017, Moody’s upgraded the senior secured rating of WP, to A1 from A2 and the senior unsecured ratings of ME to A3 from Baa1 and PN to Baa1 from Baa2.

Debt capacity is subject to the consolidated debt to total capitalization limits in the credit facilities previously discussed. As of December 31, 2016, FE and its subsidiaries could issue additional debt of approximately $4.6 billion, or incur a $2.5 billion reduction to equity, and remain within the limitations of the financial covenants required by the credit facilities.

Changes in Cash Position

As of December 31, 2016, FirstEnergy had $199 million of cash and cash equivalents compared to $131 million of cash and cash equivalents as of December 31, 2015. As of December 31, 2016 and 2015, FirstEnergy had approximately $61 million and $82 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 service provided by its utility operating subsidiaries and the sales 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, employees, tax authorities, lenders, and others for a wide range of material and services.

Net cash provided from operating activities was $3,371 million during 2016, $3,447 million during 2015 and $2,713 million during 2014.

2016 compared with 2015

Cash flows from operations decreased $76 million in 2016 compared with 2015. The year over year change in cash from operations decreased due to the following:

- A $239 million increase in cash contributions to the qualified pension plan, partially offset by;
- Higher distribution deliveries and the full year impact of net rate increases implemented in 2015 at certain Utilities;
- Higher transmission revenue, reflecting recovery of incremental operating expenses and a higher rate base;

- Lower disbursements for fuel and purchased power resulting from the lower sales volumes partially offset by lower capacity revenues at CES.

2015 compared with 2014

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 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 2016, cash used for financing activities was $22 million compared to $279 million in 2015 and $513 million of net cash provided from financing activities in 2014. 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	2016	2015	2014
	(In millions)		
New Issues			
Unsecured notes	$—	$475	$2,400
PCRBs	471	339	878
FMBs	305	295	200
Term loan	1,200	200	1,050
Senior secured notes	—	2	—
	$1,976	$1,311	$4,528
Redemptions / Repayments			
Unsecured notes	$(300)	$—	$(600)
PCRBs	(483)	(313)	(793)
FMBs	(246)	(215)	(175)
Term loan	(1,200)	(200)	—
Senior secured notes	(102)	(151)	(191)
	$(2,331)	$(879)	$(1,759)
Short-term borrowings, net	$975	$(91)	$(1,605)
Common stock dividend payments	$(611)	$(607)	$(604)

On May 1, 2016, JCP&L repaid $300 million of 5.625% senior unsecured notes at maturity.

On June 1 and July 1 of 2016, NG repurchased approximately $225 million and $60 million, respectively of PCRBs, which were subject to a mandatory put on such date. On August 15, 2016, NG remarketed the approximately $285 million of PCRBs secured by FMBs with a fixed interest rate of 4.375% and mandatory put dates ranging from June 1, 2022 to July 1, 2022.

On July 11, 2016, Penn issued $50 million of 4.24% FMBs due 2056. Proceeds received from the issuance of the FMBs were used: (i) to fund capital expenditures; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

On August 15, 2016, WP repaid $145 million of 5.875% FMBs at maturity. Also, on September 23, 2016, WP agreed to sell $475 million of new 3.84% FMBs due 2046 ($100 million), 4.09% FMBs due 2047 ($100 million) and 4.14% FMBs due 2047 ($275 million). On December 15, 2016, WP issued the $100 million of 3.84% FMBs due 2046. The remaining sales are expected to settle on September 15, 2017 and December 15, 2017, respectively. Proceeds to be received from the issuances of the FMBs were or are, as the case may be, expected to be used: (i) for general corporate purposes; and (ii) to repay a portion of WP's $275 million of 5.95% FMBs that mature on December 15, 2017.

On August 15, 2016, FG remarketed approximately $86 million of PCRBs secured by FMBs with fixed interest rates ranging from 4.25% to 4.50% and mandatory put dates ranging from May 1, 2021 to June 1, 2021.

On September 15, 2016, FG remarketed $100 million of PCRBs secured by FMBs with a fixed interest rate of 4.25% and a mandatory put of September 15, 2021.

On September 15 and 30, 2016, respectively, FG retired an aggregate of $12 million of PCRBs with original maturity dates in 2018 and 2029.

On October 17, 2016, PE issued $155 million of 3.89% FMBs due 2046. Proceeds received from the issuance were used: (i) to repay short-term borrowings incurred to repay PE's $100 million of 5.80% FMBs that matured on October 15, 2016; and (ii) for general corporate purposes.

Cash Flows From Investing Activities

Cash used for investing activities in 2016 principally represented cash used for property additions. The following table summarizes investing activities for 2016, 2015 and 2014:

	For the Years Ended December 31		
Cash Used for Investing Activities	2016	2015	2014
	(In millions)		
Property Additions:			
Regulated distribution	$1,063	$1,040	$855
Regulated transmission	1,101	1,020	1,446
Competitive energy services	619	588	939
Corporate / other	52	56	72
Nuclear fuel	232	190	233
Proceeds from asset sales	(15)	(20)	(394)
Investments	111	114	103
Asset removal costs	145	142	153
Other	(27)	(8)	(48)
	$3,281	$3,122	$3,359

2016 compared with 2015

Cash used for investing activity in 2016 increased $159 million, compared to the same period of 2015, primarily due to increases in nuclear fuel purchases and property additions. Property additions increased primarily due to higher transmission investment and CES' purchase of the remaining non-affiliated leasehold interest in Perry Unit 1. The increase in nuclear fuel was due to the scheduled Davis-Besse refueling and maintenance outage in 2016.

2015 compared with 2014

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 $426 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 $185 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, 2016, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2017	2018-2019	2020-2021	Thereafter
	(In millions)				
Long-term debt[1]	$19,881	$1,641	$ 3,968	$ 2,063	$ 12,209
Short-term borrowings	2,675	2,675	—	—	—
Interest on long-term debt[2]	12,539	986	1,736	1,556	8,261
Operating leases[3]	1,957	125	265	216	1,351
Capital leases[3]	117	32	44	26	15
Fuel and purchased power[4]	10,438	1,368	2,180	1,629	5,261
Capital expenditures [5]	1,668	647	762	259	—
Pension funding	2,565	—	827	1,032	706
Total	$51,840	$7,474	$ 9,782	$ 6,781	$ 27,803

(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, 2016.
(3) See Note 7, 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, 2016.

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 $2.9 billion in 2017, of which $0.4 billion are expected to relate to the Utilities' contracts with FES.

The table above also excludes regulatory liabilities (see Note 15, Regulatory Matters), AROs (see Note 14, Asset Retirement Obligations), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 16, 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 $13.3 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13 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-$506 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, NG purchases insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. NG is a Member Insured of NEIL, which provides coverage for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. NG, as the Member Insured and each entity with an insurable interest, purchases policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.40 billion (NG-$1.39 billion) for replacement power costs incurred during an outage after an initial 12-week waiting period.

NG, as the Member Insured and each entity with an insurable interest, is insured under property damage insurance provided by NEIL. 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. Member Insureds of NEIL pay annual premiums and are subject to retrospective premium assessments if losses exceed the accumulated funds available to the insurer. NG purchases insurance through NEIL that will pay its obligation in the event a retrospective premium call is made by NEIL, subject to the terms of the policy.

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 NG'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, 2016, was approximately $3.3 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)	$ 12
Deferred compensation arrangements(2)	559
Other(3)	10
	581
Subsidiaries’ Guarantees	
Energy and Energy-Related Contracts(4)	265
FES' guarantee of nuclear decommissioning costs(5)(6)	21
FES’ guarantee of FG’s sale and leaseback obligations	1,647
	1,933
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries(7)	373
Surety Bonds	22
Sale leaseback indemnity	58
LOCs(8)	12
	465
Total Guarantees and Other Assurances	$ 3,279

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

(2) CES related portion is $139 million, including $53 million and $86 million at FES and FENOC, respectively.

(3) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $3 million for railcar leases, and $3 million for various leases.

(4) Includes energy and energy-related contracts associated with FES.

(5) NG funded a $10 million supplemental trust in December 2016 to replace this guarantee, which will terminate in April 2017.

(6) FES provides a parental support agreement to NG of up to $400 million that may be required in the event of extraordinary circumstances. FE is working with FES to establish conditional credit support on terms and conditions to be agreed upon for the $400 million FES parental support agreement that is currently in place for the benefit of NG in the event that FES is unable to provide the necessary support to NG.

(7) Effective January 2017, FE is an indemnitor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

(8) Includes $9 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities and $3 million pledged in connection with the sale and leaseback of the Beaver Valley Unit 2 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, 2016, FES has posted collateral of $190 million and AE Supply has posted collateral of $4 million. The Regulated Distribution Segment has posted collateral of $3 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, 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, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of December 31, 2016:

Potential Additional Collateral Obligations	FES	AE Supply	Regulated	Total
	(In millions)			
Contractual Obligations for Additional Collateral				
At Current Credit Rating	$7	$ 3	$ —	$10
Upon Further Downgrade	—	—	48	48
Surety Bonds (Collateralized Amount)[1]	240	25	102	367
Total Exposure from Contractual Obligations	$247	$ 28	$ 150	$425

[1] Effective January 2017, FE is a guarantor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

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, 2016, neither FES nor AE Supply had any collateral posted with their affiliates. Moreover, a further downgrade for either FES or AE Supply would not trigger any obligations to post any such collateral.

Other Commitments, Contingencies and Assurances

FE 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, continue to provide their joint and several guaranties of the obligations of Global Holding under the facility.

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

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 $879 million as of December 31, 2016 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040.

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. Upon the completion of this transaction, NG will have obtained all of the lessor equity interests at Beaver Valley Unit 2. Therefore, upon the expiration of the Beaver Valley Unit 2 leases, NG will be the sole owner of Beaver Valley Unit 2 and entitled to 100% of the unit's output. As of December 31, 2016, OE's leasehold interest was 2.60% of Beaver Valley Unit 2 and FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

On May 23, 2016, NG completed the purchase of the 3.75% lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 for $50 million. In addition, the Perry Unit 1 leases expired in accordance with their terms on May 30, 2016, resulting in NG being the sole owner of Perry Unit 1 and entitled to 100% of the unit's output.

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 10, 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, 2016 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2017	2018	2019	2020	2021	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$4	$—	$—	$—	$ —	$ —	$4
Other external sources[2]	27	(8)	(31)	(11)	—	—	(23)
Prices based on models	(1)	—	—	—	—	—	(1)
Total[3]	$30	$(8)	$(31)	$(11)	$ —	$ —	$(20)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(107) 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, 2016, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $29 million during the next twelve months.

Equity Price Risk

As of December 31, 2016, the FirstEnergy pension plan assets were allocated approximately as follows: 46% in equity securities, 31% in fixed income securities, 8% in absolute return strategies, 10% in real estate, 1% in private equity, and 4% 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. In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016. In 2017, FirstEnergy does not have a minimum required funding obligation to its qualified pension plan due to the equity contribution. See "Note 4, Pension and Other Postemployment Benefits", of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2016, FirstEnergy's pension plan assets earned approximately 8.6%, as compared to an expected return on plan assets of 7.5%.

As of December 31, 2016, FirstEnergy's OPEB plans were invested in fixed income and equity securities. In 2016 FirstEnergy's OPEB plans have earned approximately 7.0% as compared to an annual expected return on plan assets of 7.5%.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2016, approximately 61% of the funds were invested in fixed income securities, 37% of the funds were invested in equity securities and 2% 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 $1,531 million, $925 million and $60 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2016, excluding $(2) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $93 million reduction in fair value as of December 31, 2016. 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 2016, FirstEnergy contributed approximately $2 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 7, 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	2017	2018	2019	2020	2021	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$2	$—	$—	$—	$—	$1,768	$1,770	$1,771
Average interest rate	8.9 %	— %	— %	— %	— %	3.8 %	3.8 %	
Liabilities:								
Long-term Debt:								
Fixed rate	$1,517	$1,329	$1,035	$541	$58	$14,203	$18,683	$18,627
Average interest rate	6.2 %	6.0 %	6.9 %	5.6 %	4.9 %	5.3 %	5.53 %	
Variable rate	$2	$—	$—	$—	$1,200	$—	$1,202	$1,202
Average interest rate	— %	— %	— %	— %	2.4 %	— %	2.43 %	

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 and demand 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. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the goal of 0.97% savings set in PE's plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The costs of the 2015-2017 plan are expected to be approximately $70 million, of which $43 million was incurred through December 31, 2016. 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 February 27, 2013, the MDPSC issued an 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. 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 2013 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 2013 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, as well as 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 Maryland 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 September 26, 2016, the MDPSC initiated a new proceeding to consider an array of issues relating to electric distribution system design, including matters relating to electric vehicles, distributed energy resources, advanced metering infrastructure, energy storage, system planning, rate design, and impacts on low-income customers. Initial comments in the proceeding were filed on October 28, 2016, and the MDPSC held an initial hearing on the matter on December 8-9, 2016. On January 31, 2017, the MDPSC issued a notice establishing five working groups to address these issues over the following eighteen months, and also directed the retention of an outside consultant to prepare a report on costs and benefits of distributed solar generation in Maryland.

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.

Pursuant to the NJBPU's March 26, 2015 final order in JCP&L's 2012 rate case proceeding directing that certain studies be completed, on July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which include operational and financial components. The independent consultant conducting the review issued a final report on July 27, 2016, recognizing that JCP&L is meeting the NJBPU requirements and making various operational and financial recommendations. The NJBPU issued an Order on August 24, 2016, that accepted the independent consultant’s final report and directed JCP&L, the Division of Rate Counsel and other interested parties to address the recommendations.

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 filed to participate as a respondent in that proceeding. Briefing has been completed. The oral argument was held on October 25, 2016.

On April 28, 2016, JCP&L filed tariffs with the NJBPU proposing a general rate increase associated with its distribution operations to improve service and benefit customers by supporting equipment maintenance, tree trimming, and inspections of lines, poles and substations, while also compensating for other business and operating expenses. The filing requested approval to increase annual operating revenues by approximately $142.1 million based upon a hybrid test year for the twelve months ending June 30, 2016. On November 30, 2016, JCP&L submitted to the ALJ a Stipulation of Settlement achieved with all the intervening parties providing for an annual $80 million distribution revenue increase, effective January 1, 2017. The ALJ filed an Initial Decision concluding that the Stipulation of Settlement should be approved, and the NJBPU approved the Stipulation of Settlement on December 12, 2016. As part of the Stipulation of Settlement the intervening parties agreed that JCP&L can accelerate the amortization of the 2012 major storm expenses (approximately $19 million annually) that are recovered through the SRC to achieve full recovery by December 31, 2019. On November 23, 2016, JCP&L filed an Amendment to its January 15, 2016 SRC Filing with the NJBPU, requesting that JCP&L be able to accelerate the amortization of the 2012 major storm expenses as agreed to in the Stipulation of Settlement, and a Stipulation of Settlement with NJBPU Staff and the Division of Rate Counsel regarding the SRC Filing was filed on December 27, 2016. The NJBPU approved this Stipulation of Settlement at the January 25, 2017 public meeting.

OHIO

The Ohio Companies currently operate under an ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO's Opinions and Orders issued on March 31, 2016 and October 12, 2016, include Rider DMR, which provides for the Ohio Companies to collect $132.5 million annually for three years, with the possibility of a two-year extension. The Rider DMR will be grossed up for taxes, resulting in an approved amount of approximately $204 million annually. Revenues from the Rider DMR will be excluded from the significantly excessive earnings test for the initial three-year term but the exclusion will be reconsidered upon application for a potential two-year extension. The PUCO set three conditions for continued recovery under Rider DMR: (1) retention of the corporate headquarters and nexus of operations in Akron, Ohio; (2) no change in control of the Ohio Companies; and (3) a demonstration of sufficient progress in the implementation of grid modernization programs approved by the PUCO. ESP IV also continues a base distribution rate freeze through May 31, 2024. In addition, ESP IV continues the supply of power to non-shopping customers at a market-based price set through an auction process.

ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, 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. Other material terms of ESP IV include the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs, an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016), a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045, and contributions, totaling $51 million, to fund energy conservation programs, economic development and job retention in the Ohio Companies' service territory, and a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers, and to establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On April 29, 2016 and May 2, 2016, several parties, including the Ohio Companies, filed applications for rehearing on the Ohio Companies' ESP IV with the PUCO. On September 6, 2016, while the applications for rehearing were still pending before the PUCO, the OCC and NOAC filed a notice of appeal with the Ohio Supreme Court appealing various PUCO and Attorney Examiner Entries on the parties' applications for rehearing. On September 16, 2016, the Ohio Companies intervened and filed a motion to dismiss the appeal. The PUCO resolved such applications for rehearing in the October 12, 2016 Opinion and Order. The OCC and NOAC appeal remains pending before the Ohio Supreme Court.

On November 10, 2016 and November 14, 2016, several parties, including the Ohio Companies, filed additional applications for rehearing on the Ohio Companies' ESP IV with the PUCO. The Ohio Companies' application for rehearing challenged, among other things, the PUCO's failure to adopt the Ohio Companies' suggested modifications to Rider DMR. The Ohio Companies had previously suggested that a properly designed Rider DMR would be valued at $558 million annually for eight years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio. Other parties' applications for rehearing argued, among other things, that the PUCO's adoption of Rider DMR is not supported by law or sufficient evidence. On December 7, 2016, the PUCO granted the applications for rehearing for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO. For additional information, see "FERC Matters - Ohio ESP IV PPA," below.

Under ORC 4928.66, the Ohio Companies were required to implement energy efficiency programs that achieved a total annual energy savings of 1,990 GWHs and total peak demand reduction of 486 MWs in 2015. On May 12, 2016, the Ohio Companies filed their Energy Efficiency and Peak Demand Reduction Program Status Report indicating compliance with their 2015 statutory benchmarks. In 2016, the Ohio Companies estimated the annual energy savings target and peak demand reduction target will be comparable to the 2015 targets due to the energy efficiency requirements under SB310, which amended ORC 4928.66 to freeze the energy efficiency and peak demand reduction benchmarks for 2015 and 2016. Starting in 2017, ORC 4928.66 requires the energy savings benchmark to increase by 1% and the peak demand reduction benchmark to increase by 0.75% annually thereafter through 2020.

On April 15, 2016, the Ohio Companies filed an application for approval of their three-year energy efficiency portfolio plans for the period from January 1, 2017 through December 31, 2019. The plans as proposed comply with benchmarks contemplated by ORC 4928.66 and provisions of the ESP IV, and include a portfolio of energy efficiency programs targeted to a variety of customer segments, including residential customers, low income customers, small commercial customers, large commercial and industrial customers and governmental entities. On December 9, 2016, the Ohio Companies filed a Stipulation and Recommendation with several parties that contained changes to the plan and a decrease in the plan costs. The Ohio Companies anticipate the cost of the plans will be approximately $268 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies' existing rate mechanisms. The hearings were held in January 2017.

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, 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. On January 13, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO.

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.

Following the expiration of the current DSPs, the Pennsylvania Companies will operate under new DSPs for the June 1, 2017 through May 31, 2019 delivery period, which 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 new DSPs, the supply will be provided by wholesale suppliers through 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 new DSPs include modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectible expense 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 were effective through May 31, 2016. Total Phase II costs of these plans were $174 million and are 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' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, with expected costs up to $390 million, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order with full recovery through the reconcilable EE&C riders.

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. 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. On June 9, 2016, the PPUC approved the Pennsylvania Companies' DSIC riders to be effective July 1, 2016, subject to hearings and refund or reallocation among customers. The four proceedings were consolidated by the ALJ. On January 19, 2017, in the PPUC's order approving the Pennsylvania Companies' general rate cases, discussed below, the PPUC referred the issue of whether ADIT should be included in DSIC calculations to the consolidated DSIC proceeding. On February 2, 2017, the parties to the consolidated DSIC proceeding submitted a Joint Settlement to the ALJ to resolve issues referred to by the ALJ in its June 9, 2016 Order, subject to PPUC approval, and would not result in any refund or reallocation among customers. The ADIT issue will be considered separately from the issues resolved in the Joint Settlement Petition of February 2, 2017, and is the sole issue to be litigated in the consolidated DSIC proceeding through a procedural schedule to be determined by the ALJ.

On April 28, 2016, each of the Pennsylvania Companies filed tariffs with the PPUC proposing general rate increases associated with their distribution operations to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements. The filings requested approval to increase annual operating revenues by approximately $140.2 million at ME, $158.8 million at PN, $42.0 million at Penn, and $98.2 million at WP, based upon fully projected future test years for the twelve months ending December 31, 2017 at each of the Pennsylvania Companies. As a result of the enactment of Act 40 of 2016 that terminated the practice of making a CTA when calculating a utility’s federal income taxes for ratemaking purposes, the Pennsylvania Companies submitted supplemental testimony on July 7, 2016, that quantified the value of the elimination of the CTA and outlined their plan for investing 50 percent of that amount in rate base eligible equipment as required by the new law. Formal settlement agreements for each of the Pennsylvania Companies were filed on October 14, 2016, which proposed increases in annual operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP. One item related to the calculation of DSIC rates was reserved for briefing, with briefs filed by two parties. On November 21, 2016, the ALJ issued a Recommended Decision recommending approval of the settlement agreements and dismissal of the one issue reserved for briefing. Exceptions to that Recommended Decision were filed by one party on December 1, 2016, and reply exceptions were filed by the Pennsylvania Companies on December 8, 2016. On January 19, 2017, the PPUC issued an order approving the settlements and referring the reserved issue to the Pennsylvania Companies’ consolidated DSIC proceeding. On February 3, 2017, one party filed a Petition for Reconsideration or Clarification relating to the limited issue of the scope of the record to be transferred to the DSIC proceeding, discussed above. The outcome of this request will not affect the new rates which took effect on January 27, 2017.

WEST VIRGINIA

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking. MP and PE recover net power supply costs, including fuel costs, purchased power costs and related expenses, net of related market sales revenue through the ENEC. MP's and PE's ENEC rate is updated annually.

On March 31, 2016, MP and PE filed with the WVPSC seeking approval of their Phase II energy efficiency program including three MP and PE energy efficiency programs to meet their Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, as agreed to by MP and PE, and approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of the Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. A unanimous settlement was reached by the parties on all issues and presented to the WVPSC on August 18, 2016. An order approving the settlement in full without modification was issued by the WVPSC on September 23, 2016. The Phase II program began initial implementation in November 2016.

The Staff of the WVPSC and the Consumer Advocate Division filed a Show Cause petition on August 5, 2016, requesting that the WVPSC order MP and PE to file and implement RFPs for all future capacity and energy requirements above 100 MWs and that they comply with an RFP settlement provision from the Harrison power station acquisition. MP and PE filed a timely response to the petition arguing for dismissal on September 7, 2016. On October 17, 2016, the WVPSC denied the petition filed by the Staff of the WVPSC and the Consumer Advocate Division and dismissed the case.

On August 16, 2016, MP and PE filed their annual ENEC case proposing an annual increase in rates of approximately $65 million effective January 1, 2017, which is a 4.7% increase over existing rates. The increase is comprised of a $119 million under-recovered balance as of June 30, 2016, and a projected $54 million over-recovery for the 2017 rate effective period. The parties reached a unanimous settlement providing for a $25 million increase beginning January 1, 2017 and keeping ENEC rates at the same level for a two year period. The settlement was presented to the WVPSC at a hearing on November 9, 2016. On December 9, 2016, the WVPSC approved the settlement as submitted.

On August 22, 2016, MP and PE filed an application for approval of a modernization and improvement plan for coal-fired boilers at electric power plants and cost-recovery surcharge proposing an approximate $6.9 million annual increase in rates to be effective May 1, 2017, which is a 0.5% increase over existing rates. The filing is in response to recent legislation by the West Virginia Legislature permitting accelerated recovery of costs related to modernizing and improving coal-fired boilers, including costs related to meeting environmental requirements and reducing emissions. The filing was supplemented on September 28, 2016, to add two additional projects, resulting in an approximate $7.4 million annual increase in rates. The Staff of the WVPSC filed a motion to dismiss the case arguing the new statute was not meant to recover these types of projects, but the WVPSC set the case for hearing for February 21-23, 2017. As part of the annual ENEC settlement described above, the parties agreed that MP and PE will increase ENEC rates to provide for a return of and on MATS/CSPR capital costs incurred during 2016-2017. Accordingly, MP and PE withdrew this case as part of the ENEC approval.

On December 30, 2015, MP filed an IRP with the WVPSC identifying a capacity shortfall starting in 2016 and exceeding 700 MWs by 2020 and 850 MWs by 2027. On June 3, 2016, the WVPSC accepted the IRP finding that IRPs are informational and that it must not approve or disapprove the IRP. MP issued a RFP to address its generation shortfall identified in the IRP on December 16, 2016 along with issuing a second RFP to sell its interest in Bath County. Bids were received by an independent evaluator in February

2017 for both RFPs. MP expects to execute definitive agreements with selected respondent(s) and file the appropriate applications with the WVPSC and FERC by March 15, 2017.

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 and its subsidiaries, AE Supply, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy, including FES, 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, including FES, 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, including FES, 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, including FES, 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

Ohio ESP IV PPA

On August 4, 2014, the Ohio Companies filed an application with the PUCO seeking approval of their ESP IV. ESP IV included a proposed Rider RRS, which would flow through to customers either charges or credits representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, against the revenues received from selling such output into the PJM markets. The Ohio Companies entered into stipulations which modified ESP IV, and on March 31, 2016, the PUCO issued an Opinion and Order adopting and approving the Ohio Companies’ stipulated ESP IV with modifications. FES and the Ohio Companies entered into the ESP IV PPA on April 1, 2016.

On January 27, 2016, certain parties filed a complaint with FERC against FES and the Ohio Companies requesting FERC review the ESP IV PPA under Section 205 of the FPA. On April 27, 2016, FERC issued an order granting the complaint, prohibiting any transactions under the ESP IV PPA pending authorization by FERC, and directing FES to submit the ESP IV PPA for FERC review if the parties desired to transact under the agreement. FES and the Ohio Companies did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA. FES and the Ohio Companies subsequently advised FERC of this course of action. On January 19, 2017, FERC issued an order accepting compliance filings by FES, its subsidiaries, and the Ohio Companies updating their respective market-based rate tariffs to clarify that affiliate sales restrictions under the tariffs apply to the ESP IV PPA, and also that the ESP IV PPA does not affect certain other waivers of its affiliate restrictions rules FERC previously granted these entities.

On May 2, 2016, the Ohio Companies filed an Application for Rehearing with the PUCO that included a modified Rider RRS proposal that did not involve a FERC-jurisdictional PPA. Several parties subsequently filed protests and comments with FERC alleging, among other things, that the modified Rider RRS constituted a "virtual PPA". FERC rejected these protests in its January 19, 2017 order accepting the updated market-based rate tariffs of FES, its subsidiaries, and the Ohio Companies discussed below.

On March 21, 2016, a number of generation owners filed with FERC a complaint against PJM requesting that FERC expand the MOPR in the PJM Tariff to prevent the alleged artificial suppression of prices in the PJM capacity markets by state-subsidized generation, in particular alleged price suppression that could result from the ESP IV PPA and other similar agreements. The complaint requested that FERC direct PJM to initiate a stakeholder process to develop a long-term MOPR reform for existing resources that receive out-of-market revenue. On January 9, 2017, the generation owners filed to amend their complaint to include challenges to certain legislation and regulatory programs in Illinois. On January 24, 2017, FESC, acting on behalf of its affected affiliates and along with other utility companies, filed a motion to dismiss the amended complaint for various reasons, including that the ESP IV PPA matter is now moot. In addition, on January 30, 2017, FESC along with other utility companies filed a substantive protest to the amended complaint, demonstrating that the question of the proper role for state participation in generation development should be addressed in the PJM stakeholder process. This proceeding remains pending before FERC.

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for certain 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. On June 15, 2016, various parties, including ATSI and the Utilities, filed a settlement agreement at FERC agreeing to apply a combined usage based/socialization approach to cost allocation for charges to transmission customers in the PJM region for transmission projects operating at or above 500 kV. Certain other parties in the proceeding did not agree to the settlement and filed protests to the settlement seeking, among other issues, to strike certain of the evidence advanced by FirstEnergy and certain of the other settling parties in support of the settlement, as well as provided further comments in opposition to the settlement. The PJM TOs responded to the protesting parties' various pleadings and motions. The settlement is pending before FERC.

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. On March 17, 2016, FERC denied FirstEnergy's request for rehearing of FERC's earlier order rejecting the settlement agreement and affirmed its prior ruling that ATSI must submit the cost/benefit analysis.

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 FERC denied on May 19, 2016. On July 15, 2016, the MISO TOs filed an appeal of FERC's orders with the Sixth Circuit. On November 16, 2016, the Sixth Circuit granted FirstEnergy's intervention on behalf of ATSI, the Ohio Companies, and PP, and a procedural schedule has been established. On a related issue, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

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.

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. In February and August 2016, respectively, FERC and the PPUC granted the authorization for PN and ME to contribute their transmission assets to MAIT at book value, together with the approval of related intercompany agreements, including MAIT’s participation in FirstEnergy’s regulated companies' money pool. FirstEnergy subsequently withdrew its request for authorization before the NJBPU to also transfer JCP&L's transmission assets to MAIT.

On October 28, 2016, MAIT and PJM submitted joint applications to FERC requesting authorization for (i) PJM to update its Tariff and other agreements to reflect the withdrawal of ME and PN as TOs, and (ii) MAIT to become a participating PJM TO. FERC approval would authorize MAIT to be a PJM TO, and would permit PJM to implement MAIT’s formula rate on MAIT’s behalf. On January 26, 2017, FERC issued an order granting the requested authorization and MAIT now owns and operates the transmission assets of ME and PN. On January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and asset contributions.

On October 14 and 28, 2016, MAIT submitted applications to FERC requesting authorization to issue equity, short-term debt, and long-term debt. On December 8, 2016, FERC issued an order authorizing the application to issue equity as requested. MAIT is expected to issue short-term debt and participate in the FirstEnergy regulated companies' money pool for working capital, to fund day-to-day operations, and for other general corporate purposes. Over the long-term, MAIT is expected to issue long-term debt to support capital investment and to establish an actual capital structure for ratemaking purposes. On February 3, 2017, MAIT amended its debt authorization application to provide additional information regarding recovery of its investment and debt costs. MAIT requested an order from FERC on the debt authorization by February 28, 2017. FERC's order remains pending.

MAIT Transmission Formula Rate

On October 28, 2016, MAIT submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective January 1, 2017. On November 30, 2016, various intervenors submitted protests of the proposed MAIT formula rate. Among other things, the protest asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. MAIT filed a response to the protests on December 12, 2016. On December 28, 2016, FERC Staff issued a deficiency letter with respect to the PJM-related application, which also requested additional information regarding MAIT's proposed formula rate. As a result of the deficiency letter, FERC's order on the formula rate remains pending. MAIT responded to FERC Staff's request on January 10, 2017, and requested that FERC issue an order approving the formula rate immediately after consummation of the transaction, which occurred on January 31, 2017. On February 15, 2017, MAIT filed a further answer to certain protesting parties' comments on its January 10^{th} deficiency letter response.

JCP&L Transmission Formula Rate

On October 28, 2016, after withdrawing its request to the NJBPU to transfer its transmission assets to MAIT, JCP&L submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective January 1, 2017. On November 18, 2016, a group of intervenors-including the NJBPU and New Jersey Division of Rate Counsel-filed a protest of the proposed JCP&L transmission rate. Among other things, the protest asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. On December 5, 2016, JCP&L filed a response to the protest. On December 28, 2016, FERC Staff issued a deficiency letter requesting additional information regarding JCP&L's proposed transmission rate. As a result of the deficiency letter, FERC's order on the rate remains pending. JCP&L responded to FERC Staff's request on January 10, 2017, and requested that FERC issue an order approving the formula rate effective January 1, 2017. On February 15, 2017, JCP&L filed a further answer to certain protesting parties' comments on its January 10^{th} deficiency letter response.

Competitive Generation Asset Sale

On February 17, 2017, AE Supply and AGC submitted filings with FERC for authorization to sell four natural gas generating plants and an undivided ownership interest in Bath County to Aspen for approximately $925 million, in an all cash transaction. The four natural gas plants are: Springdale Generating Facility (638 MWs), Chambersburg Generating Facility (88 MWs), Gans Generating Facility (88 MWs), and Hunlock Creek (45 MWs). The 713 MW ownership interest in Bath County represents AE Supply's indirect ownership interest in the power station. The FERC applications include a request for authorization to transfer the hydroelectric license under Part I of the FPA, and a request for authorization to transfer the FERC-jurisdictional facilities associated with the hydroelectric projects under Part II of the FPA. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once regulatory approval is obtained. The VSCC also must approve the sale of the Bath County Hydro interest. The parties expect to close the transaction in the third quarter of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents. See "Executive Summary" above for additional information regarding the transaction.

California Claims Litigation

Since 2002, AE Supply has been involved in litigation and claims based on its power sales to the California Energy Resource Scheduling division of the CDWR during 2001-2003. This litigation and claims are related to litigation and claims advanced by the California Attorney General and certain California utilities regarding alleged market manipulation of the wholesale energy markets in California during the 2000-2001 period. AE Supply negotiated a settlement with the California Attorney General and the California utilities and, on August 24, 2016, filed the settlement agreement for FERC approval. The settlement calls for AE Supply to pay, without admission of any liability, $3.6 million in settlement in principle of all remaining claims that are based on AE Supply’s power sales in the western energy markets during the 2001-2003 time period. On October 27, 2016 FERC approved this settlement, and AE Supply paid the settlement shortly thereafter.

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, 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 a 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. On January 19, 2017, FERC issued an order accepting the initial decision in part and denying it in part. Relying on its revised ROE methodology described in FERC Opinion No. 531, FERC reduced the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017. Additionally, FERC allowed recovery of costs related to land acquisitions and dispositions and legal expenses, but disallowed certain costs related to advertising and outreach. PATH filed a request for rehearing with FERC on February 20, 2017, seeking recovery of the advertising and outreach costs and requesting that the ROE be reset to 10.4%.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and its subsidiaries, Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 23, 2016, FESC, on behalf of its affiliates with market-based rate authority, submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. The filings remain pending before FERC.

ENVIRONMENTAL MATTERS

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

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 issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Various states and other stakeholders appealed the CSAPR update rule to the D.C. Circuit in November and December 2016. Depending on the outcome of the appeals and on how the EPA and the states implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's and FES' operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The 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 the 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 material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State of Delaware's CAA Section 126 petition by six months to April 7, 2017. In November 2016, the State of Maryland filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 36 EGUs, including Harrison Units 1, 2 and 3, Mansfield Unit 1 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition seeks NOx emission rate limits for the 36 EGUs by May 1, 2017. On January 3, 2017, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to July 15, 2017. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

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. 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 $286 million has been spent through December 31, 2016 ($125 million at CES and $161 million at Regulated Distribution).

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 event that excuses FG’s performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by

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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, all plants covered by this contract 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 under the contract through 2025. On May 31, 2016, the parties agreed to a stipulation that if FG’s force majeure defense is determined to be wholly or partially invalid, liquidated damages are the sole remedy available to BNSF and CSX. The arbitration panel consolidated the claims and held a liability hearing from November 28, 2016, through December 9, 2016, and, if necessary, a damages hearing is scheduled to begin on May 8, 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearing proceedings, which are scheduled to conclude February 24, 2017. 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. FG intends to vigorously assert its 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. Refer to the "Executive Summary" above for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS who are the counterparties to the coal transportation contract covering the delivery of 2.5 million tons annually through 2025, for FG’s coal-fired Bay Shore Units 2-4, deactivated on September 1, 2012, as a result of the EPA’s MATS and for FG’s W.H. Sammis Plant. The demand for arbitration was submitted to the AAA office in Washington, D.C. against FG alleging, among other things, that FG breached the agreement in 2015 and 2016 and repudiated the agreement for 2017-2025. The counterparties are seeking, among other things, damages, including lost profits through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. FG intends to vigorously assert its position in this arbitration proceeding. If it were ultimately determined that the force majeure provisions or other defenses do not excuse the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. Refer to the "Executive Summary" above for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced in the above arbitration proceedings, FG paid approximately $70 million in the aggregate in liquidated damages to settle delivery shortfalls in 2014 related to its deactivated plants, which approximated full liquidated damages under the agreements for such year related to the plant deactivations. Liquidated damages for the period 2015-2025 remain in dispute under both coal transportation agreements.

As to a specific coal supply agreement, AE Supply asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, the coal supplier commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. AE Supply has 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 approximately 5.5 million tons remaining under the contract for delivery. At this time, AE Supply cannot estimate the loss or range of loss regarding the ongoing 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, March 27, 2013 and October 18, 2016, 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

FirstEnergy has established a goal to reduce CO_2 emissions by 90% below 2005 levels by 2045. 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.

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. 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. The EPA released its final regulations in August 2015 (which have been stayed by the U.S. Supreme Court), 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. 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, 2016, 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 material.

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 was ratified by the requisite number of countries (i.e. at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius are effective on November 4, 2016. It remains unclear whether and how the results of the 2016 United States election could impact the regulation of GHG emissions at the federal and state level. 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 material 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 material.

On September 30, 2015, the EPA finalized new, more stringent effluent limits for the Steam Electric Power Generating category (40 CFR Part 423) 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 not currently expected, any changes in timing and closure plan requirements in the future, including changes resulting from the strategic review at CES, could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG 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 CCRs from the Bruce Mansfield plant are being beneficially reused with the majority used for reclamation of a site owned by the Marshall County Coal Company in Moundsville, W. Va. and the remainder recycled into drywall by National Gypsum. These beneficial reuse options should be sufficient for ongoing plant operations, however, the Bruce Mansfield plant is pursuing other options. 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 Notices of Appeal 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, 2016 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 $137 million have been accrued through December 31, 2016. Included in the total are accrued liabilities of approximately $89 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 loss 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, 2016, FirstEnergy had approximately $2.5 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 FES no longer maintains investment grade credit ratings from either S&P or Moody’s, NG funded a $10 million supplemental trust in 2016 in lieu of the FES parental guarantee that would be required to support the decommissioning of the spent fuel storage facilities. The termination of the FES parental guarantee is subject to NRC review. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantees, as appropriate.

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 to the NRC related to the laminar cracking in the Shield Building.

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. Although a majority of the necessary modifications and upgrades at FirstEnergy’s nuclear facilities have been implemented, the improvements still remain subject to regulatory approval.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. In addition to the $500 million credit facility with FE discussed above, FE is working with FES to establish conditional credit support on terms and conditions to be agreed upon for the $400 million FES parental support agreement that is currently in place for the benefit of NG in the event that FES is unable to provide the necessary support to NG.

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 15, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

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

Revenue Recognition

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

Regulatory Accounting

FirstEnergy’s regulated distribution and regulated transmission segments are subject to regulations that set the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to be recovered. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. See Note 15, Regulatory Matters for additional information.

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.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016. The independent fiduciary representing the pension plan with respect to the equity contribution fully liquidated the FE common stock by January 31, 2017.

FirstEnergy recognizes a pension and OPEB mark-to-market adjustment for 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, 2016, 2015, and 2014 were $194 million ($147 million net of amounts capitalized), $369 million ($242 million net of amounts capitalized), and $1,243 million ($835 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 4.25%, 4.50% and 4.25% as of December 31, 2016, 2015 and 2014, respectively. The assumed discount rates for OPEB were 4.00%, 4.25% and 4.00% as of December 31, 2016, 2015 and 2014, 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 2016, FirstEnergy’s qualified pension and OPEB plan assets experienced earnings of $472 million or 8.2% compared to losses of $(172) million, or (2.7)% in 2015 and earnings of $387 million, or 6.2% in 2014 and assumed a 7.50% rate of return on plan assets in 2016 and a 7.75% expected rate of return in 2015 and 2014 which generated $429 million, $476 million and $496 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 2017 is 7.5%.

During 2016, the Society of Actuaries released its updated mortality improvement scale for pension plans, MP-2016, incorporating three additional years of SSA data on U.S. population mortality. MP-2016 incorporates SSA mortality data from 2012 to 2014 and a slight modification of two input values designed to improve the model’s year-over-year stability. The updated improvement scale indicates a slight decline in life expectancy as a result of the slower average rate of mortality improvement. Due to the additional years of data on population mortality, the RP2014 mortality table with the projection scale MP-2016 was utilized to determine the 2016 benefit cost and obligation as of December 31, 2016 for the FirstEnergy pension and OPEB plans.The impact of using the projection scale MP-2016 resulted in a decrease in the projected benefit obligation of $141 million and $8 million for the pension and OPEB plans, respectively, and was included in the 2016 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.25% for pension, 4.00% for OPEB and an estimated return on assets of 7.5%, FirstEnergy expects its 2017 pre-tax net periodic benefit cost (including amounts capitalized) to be approximately $78 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2017). 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, 2016.

Postemployment Benefits Expense (Credits)	2016	2015	2014
	(In millions)		
Pension	$277	$316	$939
OPEB	(40)	(61)	(101)
Total	$237	$255	$838

Health care cost trends continue to increase and will affect future OPEB costs. The 2016 composite health care trend rate assumptions were approximately 6.0-5.5%, compared to 6.0-5.5% in 2015, 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 2017 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%	288	19	$307
Long-term return on assets	Decrease by .25%	15	1	$16
Health care trend rate	Increase by 1.0%	N/A	22	$22

See Note 4, Pension and Other Postemployment Benefits for additional information

Long-Lived Assets

FirstEnergy evaluates long-lived assets classified as held and used for impairment when events or changes in circumstances indicate the carrying value of the long-lived assets may not be recoverable. First, the estimated undiscounted future cash flows attributable to the assets is compared with the carrying value of the assets. If the carrying value is greater than the undiscounted future cash flows, an impairment charge is recognized equal to the amount the carrying value of the assets exceeds its estimated fair value. See Note 1, Organization and Basis of Presentation.

See Note 2, Asset Impairments for impairments recognized during 2016 and 2015.

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, 2016, are described further in "Note 14, Asset Retirement Obligations".

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

in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. 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 6, 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.

As of July 31, 2016, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units' goodwill, assessing economic, industry and market considerations in addition to the reporting units' 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.

See Note 2, Asset Impairments for further discussion of CES goodwill impairment charge recognized during 2016.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers". Subsequent accounting standards updates have been issued which amend and/or clarify the application of ASU 2014-09. The core principle of the new guidance is that an entity recognizes revenue 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. More detailed disclosures will also be required to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, the new revenue recognition guidance will be effective for annual and interim reporting periods beginning after December 15, 2017. Earlier adoption is permitted for annual and interim reporting periods beginning after December 15, 2016. FirstEnergy will not early adopt the standards. The standards shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy has evaluated a significant portion of its revenues and preliminarily expects limited impacts to current revenue recognition practices, dependent on the resolution of industry issues including accounting for contributions in aid of construction and the ability to recognize revenue for contracts where collectibility is in question. FirstEnergy continues to assess the remainder of its revenue streams and the impact on its financial statements and disclosures as well as which transition method it will select to adopt the guidance.

On August 27, 2014, the FASB issued ASU 2014-15, "Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." In connection with preparing financial statements for each annual and interim reporting period, the ASU requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Disclosures are required when management identifies conditions or events that raise substantial doubt. The new requirements were effective for the annual period ended December 31, 2016.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities", which primarily affects 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 for certain provisions 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.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)", which will require organizations that lease assets with lease terms of more than twelve months to recognize assets and liabilities for the rights and obligations created by those leases on their balance sheets. In addition, new qualitative and quantitative disclosures of the amounts, timing, and uncertainty of cash flows arising from leases will be required. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. Lessors and lessees will be required to apply a modified retrospective transition approach, which requires adjusting the accounting for any leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. Any leases that expire before the initial application date will not require any accounting adjustment. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In March of 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting", which simplifies several aspects of the accounting for employee share-based payment. The new guidance will require all income tax effects of awards to be recognized in the income statement when the awards vest or are settled. It also will not require liability accounting when an employer repurchases more of an employee’s shares for tax withholding purposes. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. Upon adoption, January 1, 2017, FirstEnergy elected to account for forfeitures as they occur. The adoption of the ASU did not have a material impact on FirstEnergy's financial statements.

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments", which removes all recognition thresholds and will require companies to recognize an allowance for credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost that the company expects to collect over the instrument's contractual life. The ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted for fiscal years beginning after December 15, 2018. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments". The standard is intended to eliminate diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows, including the presentation of debt prepayment or debt extinguishment costs, all of which will be classified as financing activities. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted for all entities. FirstEnergy expects to adopt this ASU in 2017 and does not expect this ASU to have a material effect on its financial statements.

In October 2016, the FASB issued ASU 2016-16, " Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory". ASU 2016-16 eliminates the exception for all intra-entity sales of assets other than inventory, which allows companies to defer the tax effects of intra-entity asset transfers. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller's tax jurisdiction when the intra-entity transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. Any deferred tax asset that arises in the buyer's jurisdiction would also be recognized at the time of the transfer. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted and the modified retrospective approach will be required for transition to the new guidance, with a cumulative-effect adjustment recorded in retained earnings as of the beginning of the period of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash" that will require entities to show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. As a result, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statement of cash flows. When cash, cash equivalents, restricted cash and restricted cash equivalents are presented in more than one line item on the balance sheet, the new guidance requires a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2019. Early adoption in an interim period is permitted, but any adjustments must be reflected as of the beginning of the fiscal year that includes that interim period. FirstEnergy does not expect this ASU to have a material effect on its financial statements.

Additionally, during 2016, the FASB issued the following ASUs:
- ASU 2016-05, "Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships,"
- ASU 2016-06, "Contingent Put and Call Options in Debt Instruments (a consensus of the FASB Emerging Issues Task Force),"
- ASU 2016-07, "Simplifying the Transition to the Equity Method of Accounting," and
- ASU 2016-17, "Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control."

FirstEnergy does not expect these ASUs to have a material effect on its financial statements.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES, a subsidiary of FE, was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to retail and wholesale customers. FES also owns and operates, through its FG subsidiary, fossil generating facilities and owns, through its NG subsidiary, nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and purchases 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. Prior to April 1, 2016, FES financially purchased the uncommitted output of AE Supply's generation facilities under a PSA. On December 21, 2015, FES agreed, under a PSA, to physically purchase all the output of AE Supply's generation facilities effective April 1, 2016. FES and AE Supply are evaluating the possible termination of the PSA.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey, and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States.

FES is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and DR programs, as well as regulatory and legislative actions, such as MATS among other factors. FES attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

Today, FES' competitive generation portfolio is comprised of more than 10,000 MWs of generation, primarily from coal, nuclear and natural gas and oil fuel sources. The assets generate approximately 60-65 million MWHs annually, with up to an additional 15 million MWHs available from purchased power agreements for wind, solar, FES' entitlement in OVEC and, as discussed above, FES' PSA with AE Supply.

Over the past several years, FES has been impacted by a prolonged decrease in demand and excess generation supply in the PJM Region, which has resulted in a period of protracted low power and capacity prices. To address this, FES sold or deactivated approximately 2,700 MWs of competitive generation from 2012 to 2015. Additionally, FES has continued to focus on cost reductions, including those identified as part of FirstEnergy's previously disclosed cash flow improvement plan.

However, the energy and capacity markets continue to be weak, as evidenced by the significantly depressed capacity prices from the 2019/2020 PJM Base Residual Auction in May of 2016 as well as the current forward pricing and the long-term fundamental view on energy and capacity prices, which resulted in a non-cash pre-tax impairment charge of $23 million recognized in the second quarter of 2016 representing the total amount of goodwill at FES.

As part of a continual process to evaluate its overall generation business, on July 22, 2016, FirstEnergy announced its intent to exit the 136 MW Bay Shore Unit 1 generating station by October 2020 and to deactivate Units 1-4 of the W.H. Sammis generating station totaling 720 MWs by May 2020, resulting in a $517 million non-cash pre-tax impairment charge in the second quarter of 2016. Furthermore, in November of 2016, FirstEnergy announced that it had begun a strategic review of its competitive operations, including FES, as it transitions to a fully regulated utility with a target to implement its exit from competitive operations by mid-2018.

Although FirstEnergy is targeting mid-2018 to exit from competitive operations, the options to exit are still uncertain, but could include one or more of the following:

- Legislative or regulatory solutions for generation assets that recognize their environmental or energy security benefits,
- Additional asset sales and/or plant deactivations,
- Restructuring FES debt with its creditors, and/or
- Seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

Furthermore, adverse outcomes in previously disclosed disputes regarding long term-coal transportation contracts and/or the inability to extend or refinance debt maturities at FES subsidiaries, could accelerate management's targeted timeline and limit its options to exit competitive operations at FES to either restructuring debt with FES' creditors or seeking protection under U.S. bankruptcy laws.

As part of assessing the viability of strategic alternatives, FirstEnergy determined that the carrying value of long-lived assets of the competitive business were not recoverable, specifically given FirstEnergy’s target to implement its exit from competitive operations by mid-2018, significantly before the end of their original useful lives, and the anticipated cash flows over this shortened period. As a result, FES recorded a non-cash pre-tax impairment charge of $8,082 million in the fourth quarter of 2016 to reduce the carrying value of certain assets to their estimated fair value, including long-lived assets such as generating plants and nuclear fuel, as well as other assets such as materials and supplies.

FES continues to be managed conservatively due to the stress of weak energy prices, insufficient results from recent capacity auctions and anemic demand forecasts that have lowered the value of the business. Furthermore, the credit quality of FES, specifically its unsecured debt rating of Caa1 at Moody’s, CCC+ at S&P and C at Fitch and negative outlook from each of the rating agencies has challenged its ability to hedge generation with retail and forward wholesale sales due to collateral requirements that otherwise would reduce available liquidity. A lack of viable alternative strategies for its competitive portfolio has and would further stress the financial condition of FES. As a result, FES' contract sales are expected to decline from 52 million MWHs in 2016 to 40-45 million MWHs in 2017, and to 35-40 million MWHs in 2018. While the reduced contract sales will decrease potential collateral requirements, market price volatility may significantly impact FES' financial results due to the increased exposure to the wholesale spot market.

As previously disclosed, FES has $130 million of debt maturities that need to be refinanced in 2017 (and $515 million of maturing debt in 2018 beginning in the second quarter). Based on its current senior unsecured debt rating and current capital structure, reflecting the impact of the impairment charges discussed above, as well as the forecasted decline in wholesale forward market prices over the next few years, these debt maturities will be difficult to refinance, even on a secured basis, which would further stress FES' anticipated liquidity. Furthermore, lack of clarity regarding the timing and viability of alternative strategies, including additional asset sales or deactivations and/or converting generation from competitive operations to a regulated or regulated-like construct in a way that provides FES with the means to satisfy its obligations over the long-term may require FES to restructure debt and other financial obligations with its creditors or seek protection under U.S bankruptcy laws. Although management is exploring capital and other cost reductions, asset sales, and other options to improve cash flow as well as continuing with legislative efforts to explore a regulatory solution, these obligations and their impact on liquidity raise substantial doubt about FES’ ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern.

For additional information with respect to FES, please see the information contained in FirstEnergy’s Management’s Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: FirstEnergy's Business and Executive Summary, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Operating results decreased $5,537 million in 2016 compared to 2015, primarily resulting from the asset impairment charges discussed above. In addition to the asset impairment charges, operating results were impacted by lower mark-to-market gains on commodity contract positions, a lower Pension and OPEB mark-to-market adjustment and higher settlement and termination costs related to coal contracts. Excluding these items, year-over-year operating results were impacted by lower sales volumes, a termination charge associated with an FES customer contract, and higher retirement and employee benefit costs, partially offset by higher capacity revenue and lower fuel, transmission and purchased power costs.

Revenues -

Total revenues decreased $607 million in 2016, as compared to 2015, primarily due to lower sales volumes. Revenues were also impacted by higher capacity revenues, an increase in short-term (net hourly position) transactions at higher rates, and higher net gains on financially settled contracts, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$812	$1,269	$ (457)
Governmental Aggregation	814	1,012	(198)
Mass Market	169	265	(96)
POLR	583	712	(129)
Structured Sales	440	535	(95)
Total Contract Sales	2,818	3,793	(975)
Wholesale	1,350	902	448
Transmission	70	122	(52)
Other	160	188	(28)
Total Revenues	$4,398	$5,005	$ (607)

MWH Sales by Channel	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	15,310	23,585	(35.1)%
Governmental Aggregation	13,730	15,443	(11.1)%
Mass Market	2,431	3,878	(37.3)%
POLR	9,969	11,950	(16.6)%
Structured Sales	11,004	12,486	(11.9)%
Total Contract Sales	52,444	67,342	(22.1)%
Wholesale	13,812	2,188	531.3 %
Total MWH Sales	66,256	69,530	(4.7)%

The following table summarizes the price and volume factors contributing to changes in revenues:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(445)	$(12)	$ —	$ —	$(457)
Governmental Aggregation	(112)	(86)	—	—	(198)
Mass Market	(99)	3	—	—	(96)
POLR	(118)	(11)	—	—	(129)
Structured Sales	(63)	(32)	—	—	(95)
Wholesale	274	52	98	24	448

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflects the continuation of FES' strategy to more effectively hedge its generation, as discussed above. The Direct, Governmental Aggregation and Mass Market customer base was 1.1 million as of December 31, 2016, compared to 1.6 million as of December 31, 2015. Although unit pricing was lower year-over-year in the Direct and Governmental Aggregation channels, the decrease was primarily attributable to lower capacity expense, as discussed below, which is a component of the retail price.

The decrease in POLR sales of $129 million was primarily due to lower volumes. Structured Sales decreased $95 million, primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues increased $448 million, primarily due to an increase in short-term (net hourly position) transactions at higher rates, an increase in capacity revenue, and higher net gains on financially settled contracts. Capacity revenue increased as a result of a change in a PSA between FES and AE Supply, as discussed above.

Transmission revenue decreased $52 million, primarily due to lower congestion revenues associated with less volatile market conditions.

Other revenues decreased $28 million, primarily due to the absence of a gain on the sale of property to a regulated affiliate in 2015 and lower lease revenues from the expiration of a nuclear sale-leaseback agreement.

Operating Expenses -

Total operating expenses increased $8,067 million in 2016 compared to 2015.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2016 compared with 2015:

Operating Expense	Source of Change Increase (Decrease) Volumes	Prices	Loss on Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(103)	$(64)	$ 70	$ —	$(97)
Nuclear Fuel	1	5	—	—	6
Affiliated Purchased Power	(30)	(68)	369	—	271
Non-affiliated Purchased Power	(409)	(21)	—	(234)	(664)

Fossil and nuclear fuel costs decreased $91 million, primarily due to lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as described above, as well as lower unit prices on fossil fuel contracts. Additionally, fuel costs were impacted by higher settlement and termination costs on coal contracts.

Affiliated purchased power costs increased $271 million, primarily associated with lower net gains on settled contracts with AE Supply resulting from lower wholesale spot market prices.

Non-affiliated purchased power costs decreased $664 million due to lower volumes ($409 million), lower prices ($21 million) and lower capacity expenses ($234 million). Lower volumes primarily resulted from lower contract sales, as discussed above, partially offset by higher economic purchases resulting from the low wholesale spot market energy price environment. The decrease in capacity expense was primarily the result of lower contract sales and lower capacity rates associated with FES' retail sales obligations.

Other operating expenses decreased $31 million in 2016, compared to 2015 due to the following:

- Fossil operating costs decreased $12 million, primarily as a result of the deactivation of certain fossil plants in 2015, partially offset by increased outage costs and higher employee benefit costs
- Nuclear operating costs decreased $39 million, primarily as a result of lower refueling outage costs, partially offset by higher employee benefit costs. There were two refueling outages in 2016 as compared to three refueling outages in 2015.
- Retirement benefit costs increased $30 million.
- Transmission expenses decreased $145 million, primarily due to lower congestion and market-based ancillary costs associated with less volatile market conditions as compared to 2015, as well as lower load requirements.
- Other operating expenses increased $135 million, primarily due to lower mark-to-market gains on commodity contract positions of $85 million and a $37 million charge associated with the termination of an FES customer contract.

The Pension and OPEB mark-to-market adjustment decreased $9 million to $48 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate, partially offset by higher than expected asset returns and changes in other actuarial assumptions.

Depreciation expense increased $12 million, primarily as a result of a higher asset base.
General taxes decreased $10 million, primarily due to lower gross receipts taxes associated with lower retail sales volumes.

Impairment of assets increased $8,589 million, primarily due to impairments of the competitive generation assets discussed above.

Other Expense -

Total other expense decreased $84 million in 2016 compared to 2015, primarily due to lower OTTI on NDT investments.

Income Taxes (Benefits) -

FES' effective tax rate was 35.4% and 44.2% in 2016 and 2015, respectively. The decrease in the effective tax rate on pre-tax losses is primarily due to valuation allowances of $151 million recorded against state and local NOL carryforwards that management believes, more likely than not, will not be realized as well as the impairment of $23 million of goodwill which is non-deductible for tax purposes.

Changes in Cash Position

FES expects to rely primarily on internal sources of funds, specifically a two-year secured line of credit with FE of up to $500 million, as further described below. Additionally, FES subsidiaries have debt maturities in 2017 and 2018 of $130 million and $515 million, respectively. The inability to refinance such debt maturities at FES could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under its credit facility with FE, (iii) further asset sales or plant deactivations, and/or (iv) seek protection under bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under bankruptcy laws.

FES and AE Supply terminated their unsecured $1.5 billion credit facility (commitments of $900 million and $600 million for FES and AE Supply, respectively) and FES entered into a new, two-year secured credit facility with FE in which FE provided a committed line of credit to FES of up to $500 million and additional credit support of up to $200 million to cover a $169 million surety bond for the benefit of the PA DEP with respect to LBR, and other bonds as designated in writing to FE. In connection with the cancellation of the prior FES/AE Supply facility and entry into the new FES secured facility with FE, certain commitments and amendments associated with shared services and operational matters were made including, without limitation, as follows: (i) FE reaffirmed its obligations under the Intercompany Tax Allocation Agreement, and (ii) amendments to the Service Agreement by and among FESC, FES, FG and NG, to prevent termination until the earlier of December 31, 2018, or a change in control of FES or its subsidiaries. In addition, a separate money pool for use by FES, its subsidiaries and FENOC is expected to be established in the first quarter of 2017 at which time those companies will no longer have access to the unregulated companies' money pool.

FES continues to be managed conservatively due to the stress of weak power prices, insufficient proceeds from recent capacity auctions and anemic demand forecasts that have lowered the value of the business. Furthermore, the credit quality of FES, specifically its unsecured debt rating of Caa1 at Moody’s, CCC+ at S&P and C at Fitch and negative outlook from each of the rating agencies has challenged its ability to hedge generation with retail and forward wholesale sales without collateral obligations, which reduce the business units available liquidity. Although FES has access to a $500 million credit facility with FE, which it expects to use in lieu of borrowing under the unregulated companies' money pool, all of which is available as of January 31, 2017, these conditions are a significant challenge to FES. Furthermore, lack of viable alternative strategies for its competitive portfolio would further stress the liquidity and financial condition of FES.

Cash Flows From Operating Activities

FES' most significant sources of cash are derived from electric service provided by the sales of energy and related products and services. The most significant use of cash from operating activities is to buy electricity in the wholesale market and pay fuel suppliers, employees, tax authorities, lenders, and others for a wide range of material and services.

Net cash provided from operating activities was $785 million during 2016, $1,151 million during 2015 and $571 million during 2014. Cash flows from operations decreased $366 million in 2016 compared with 2015 due to a $138 million pension trust contribution in 2016 and increased cash collateral postings primarily associated with higher margin requirements by counterparties due to FES' credit rating downgrades in 2016; partially offset by increased capacity revenues, as discussed above in "Results of Operations".

Cash Flows From Financing Activities

In 2016, cash provided from financing activities was $57 million, compared to cash used for financing activities of $272 million in 2015, and cash provided from financing activities of $246 million in 2014. 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	2016	2015	2014
	(In millions)		
New Issues			
PCRBs	$471	$341	$878
Redemptions / Repayments			
PCRBs	$(484)	$(316)	$(742)
Senior secured notes	(23)	(95)	(74)
	$(507)	$(411)	$(816)
Short-term borrowings, net	$101	$(126)	$(301)
Common stock dividend payments	$—	$(70)	$—

On June 1 and July 1 of 2016, NG repurchased approximately $225 million and $60 million, respectively of PCRBs, which were subject to a mandatory put on such date. On August 15, 2016, NG remarketed the approximately $285 million of PCRBs secured by FMBs with a fixed interest rate of 4.375% and mandatory put dates ranging from June 1, 2022 to July 1, 2022.

On August 15, 2016, FG remarketed approximately $86 million of PCRBs secured by FMBs with fixed interest rates ranging from 4.25% to 4.50% and mandatory put dates ranging from May 1, 2021 to June 1, 2021.

On September 15, 2016, FG remarketed $100 million of PCRBs secured by FMBs with a fixed interest rate of 4.25% and a mandatory put of September 15, 2021.

On September 15 and 30, 2016, respectively, FG retired an aggregate of $12 million of PCRBs with original maturity dates in 2018 and 2029.

Cash Flows From Investing Activities

Cash used for investing activities in 2016 principally represented cash used for property additions and nuclear fuel. The following table summarizes investing activities for 2016, 2015 and 2014:

	For the Years Ended December 31		
Cash Used for Investing Activities	2016	2015	2014
	(In millions)		
Property Additions	$546	$627	$839
Nuclear fuel	232	190	233
Proceeds from asset sales	(9)	(13)	(307)
Investments	56	68	56
Other	17	7	(4)
	$842	$879	$817

Cash used for investing activity in 2016 decreased $37 million, compared to the same period of 2015, primarily due to lower property additions, partially offset by an increase in nuclear fuel purchases. Property additions decreased due to the purchase of the non-affiliated leasehold interest in Perry Unit 1 during 2015. The increase in nuclear fuel was due to the scheduled Davis-Besse refueling and maintenance outage in 2016.

Market Risk Information

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

Commodity Price Risk

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

Sources of information for the valuation of commodity derivative assets and liabilities as of December 31, 2016 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2017	2018	2019	2020	2021	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$4	$—	$—	$—	$—	$—	$4
Other external sources[2]	60	24	—	—	—	—	84
Prices based on models	(3)	—	—	—	—	—	(3)
Total	$61	$24	$—	$—	$—	$—	$85

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.

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FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2016, an increase in commodity prices of 10% would decrease net income by approximately $29 million during the next twelve months.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

Year of Maturity	2017	2018	2019	2020	2021	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$—	$—	$—	$—	$ —	$ 875	$875	$875
Average interest rate	— %	— %	— %	— %	—%	4.3 %	4.3 %	
Liabilities:								
Long-term Debt:								
Fixed rate	$34	$141	$90	$177	$ —	$ 2,556	$2,998	$1,553
Average interest rate	3.2 %	5.6 %	3.0 %	5.7 %	—%	4.5 %	4.6 %	
Variable rate	$2	$—	$—	$—	$ —	$ —	$2	$2
Average interest rate	— %	— %	— %	— %	—%	— %	— %	

Equity Price Risk

NDT funds have been established to satisfy NG's nuclear decommissioning obligations. Included in FES' NDT are fixed income, equities and short-term investments carried at market values of approximately $874 million, $634 million and $42 million, respectively, as of December 31, 2016, excluding $2 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $63 million reduction in fair value as of December 31, 2016. NG recognizes in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FES' NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

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

Wholesale Credit Risk

FES measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FES has a legally enforceable right of offset. FES monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. The majority of FES' energy contract counterparties maintain investment-grade credit ratings.

Retail Credit Risk

FES' 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, FES' retail credit risk may be adversely impacted.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORT

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 2016 consolidated financial statements as stated in their audit report included herein. As discussed in Note 1 to the consolidated financial statements, FirstEnergy Corp. is engaged in a strategic review of its competitive operations and its wholly-owned subsidiary, FirstEnergy Solutions Corp. (FES), is facing challenging market conditions impacting FES' liquidity.

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 2016.

MANAGEMENT REPORT

Management’s Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company’s 2016 consolidated financial statements as stated in their audit report included herein.

The accompanying consolidated financial statements have been prepared assuming that FirstEnergy Solutions Corp. will continue as a going concern. As discussed in Note 1 to the financial statements, FirstEnergy Solutions Corp.’s current financial position and the challenging market conditions impacting liquidity raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

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

FirstEnergy’s Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee’s findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company’s independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm’s report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm’s independence. The Committee also reviews management’s programs to monitor compliance with the Company’s policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2016.

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 (loss), comprehensive income (loss), common stockholders' equity, and of cash flows, present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, 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, FirstEnergy Corp. is engaged in a strategic review of its competitive operations and its wholly-owned subsidiary, FirstEnergy Solutions Corp. (FES), is facing challenging market conditions impacting FES' liquidity.
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

Cleveland, Ohio
February 21, 2017

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income (loss) and of comprehensive income (loss), of common stockholder’s equity, and of cash flows, present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

The accompanying consolidated financial statements have been prepared assuming that FirstEnergy Solutions Corp. will continue as a going concern. As discussed in Note 1 to the financial statements, FirstEnergy Solutions Corp.’s current financial position and the challenging market conditions impacting liquidity raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ PricewaterhouseCoopers LLP

Cleveland, Ohio
February 21, 2017

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(In millions)	For the Years Ended December 31 2016	2015	2014
REVENUES:			
Regulated Distribution	$9,629	$9,625	$9,102
Regulated Transmission	1,151	1,011	769
Unregulated businesses	3,782	4,390	5,178
Total revenues*	14,562	15,026	15,049
OPERATING EXPENSES:			
Fuel	1,666	1,855	2,280
Purchased power	3,813	4,318	4,716
Other operating expenses	3,858	3,749	3,962
Pension and OPEB mark-to-market adjustment	147	242	835
Provision for depreciation	1,313	1,282	1,220
Amortization of regulatory assets, net	320	268	12
General taxes	1,042	978	962
Impairment of assets (Note 2)	10,665	42	—
Total operating expenses	22,824	12,734	13,987
OPERATING INCOME (LOSS)	(8,262)	2,292	1,062
OTHER INCOME (EXPENSE):			
Investment income (loss)	84	(22)	72
Impairment of equity method investment (Note 2)	—	(362)	—
Interest expense	(1,157)	(1,132)	(1,081)
Capitalized financing costs	103	117	118
Total other expense	(970)	(1,399)	(891)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(9,232)	893	171
INCOME TAXES (BENEFITS)	(3,055)	315	(42)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(6,177)	578	213
Discontinued operations (net of income taxes of $69) (Note 20)	—	—	86
NET INCOME (LOSS)	$(6,177)	$578	$299
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$(14.49)	$1.37	$0.51
Basic - Discontinued Operations (Note 20)	—	—	0.20
Basic - Net Income (Loss)	$(14.49)	$1.37	$0.71

Diluted - Continuing Operations	$(14.49)	$1.37	$0.51
Diluted - Discontinued Operations (Note 20)	—	—	0.20
Diluted - Net Income (Loss)	$(14.49)	$1.37	$0.71
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	426	422	420
Diluted	426	424	421
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$1.44	$1.44	$1.44

* Includes excise tax collections of $406 million, $416 million and $420 million in 2016, 2015 and 2014, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)	For the Years Ended December 31 2016	2015	2014
NET INCOME (LOSS)	$(6,177)	$578	$299
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(59)	(116)	(76)
Amortized losses (gains) on derivative hedges	8	5	(2)
Change in unrealized gain on available-for-sale securities	55	(11)	26
Other comprehensive income (loss)	4	(122)	(52)
Income taxes (benefits) on other comprehensive income (loss)	1	(47)	(14)
Other comprehensive income (loss), net of tax	3	(75)	(38)
COMPREHENSIVE INCOME (LOSS)	$(6,174)	$503	$261

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, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 199	$ 131
Receivables-		
Customers, net of allowance for uncollectible accounts of $53 in 2016 and $69 in 2015	1,440	1,415
Other, net of allowance for uncollectible accounts of $1 in 2016 and $5 in 2015	175	180
Materials and supplies, at average cost	564	785
Prepaid taxes	98	135
Derivatives	140	157
Collateral	176	70
Other	158	167
	2,950	3,040
PROPERTY, PLANT AND EQUIPMENT:		
In service	43,767	49,952
Less — Accumulated provision for depreciation	15,731	15,160
	28,036	34,792
Construction work in progress	1,351	2,422
	29,387	37,214
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,514	2,282
Other	512	506
	3,026	2,788
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	6,418
Regulatory assets	1,014	1,348
Other	1,153	1,286
	7,785	9,052
	$ 43,148	$ 52,094
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,685	$ 1,166
Short-term borrowings	2,675	1,708
Accounts payable	1,043	1,075
Accrued taxes	580	519
Accrued compensation and benefits	363	334
Derivatives	78	106
Collateral	42	52
Other	660	642
	7,126	5,602
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 442,344,218 and 423,560,397 shares outstanding as of December 31, 2016 and December 31, 2015,	44	42

respectively		
Other paid-in capital	10,555	9,952
Accumulated other comprehensive income	174	171
Retained earnings (Accumulated deficit)	(4,532)	2,256
Total common stockholders' equity	6,241	12,421
Noncontrolling interest	—	1
Total equity	6,241	12,422
Long-term debt and other long-term obligations	18,192	19,099
	24,433	31,521
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	3,765	6,773
Retirement benefits	3,719	4,245
Asset retirement obligations	1,482	1,410
Deferred gain on sale and leaseback transaction	757	791
Adverse power contract liability	162	197
Other	1,704	1,555
	11,589	14,971
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16)		
	$ 43,148	$ 52,094

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
Balance, January 1, 2014	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 4)				(53)	
Stock-based compensation			20		
Cash dividends declared on common stock					(604)
Stock Investment Plan and certain share-based benefit plans	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 4)				(72)	
Stock-based compensation			45		
Cash dividends declared on common stock					(607)
Stock Investment Plan and certain share-based benefit plans	2,457,827		60		
Balance, December 31, 2015	423,560,397	42	9,952	171	2,256
Net loss					(6,177)
Amortized gains on derivative hedges, net of $3 million of income taxes				5	
Change in unrealized gain on investments, net of $21 million of income taxes				34	
Pension and OPEB, net of $23 million of income tax benefits (Note 4)				(36)	
Stock-based compensation			49		
Cash dividends declared on common stock					(611)
Stock Investment Plan and certain share-based benefit plans	2,685,946		56		
Stock issuance (Note 12)	16,097,875	2	498		
Balance, December 31, 2016	442,344,218	$ 44	$10,555	$ 174	$ (4,532)

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31		
(In millions)	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$(6,177)	$578	$299
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	1,997	1,922	1,592
Impairment of assets	10,665	42	—
Investment impairment, including equity method investments	21	464	37
Pension and OPEB mark-to-market adjustment	147	242	835
Deferred income taxes and investment tax credits, net	(3,063)	284	162
Deferred costs on sale leaseback transaction, net	49	48	48
Deferred purchased power and fuel costs	(30)	(105)	(115)
Asset removal costs charged to income	54	55	28
Retirement benefits	64	(20)	(53)
Commodity derivative transactions, net (Note 11)	9	(73)	64
Pension trust contributions	(382)	(143)	—
Gain on sale of investment securities held in trusts	(50)	(23)	(64)
Lease payments on sale and leaseback transaction	(120)	(131)	(137)
Income from discontinued operations (Note 20)	—	—	(86)
Changes in current assets and liabilities-			
Receivables	(11)	184	139
Materials and supplies	41	(15)	(65)
Prepayments and other current assets	27	(10)	126
Accounts payable	(37)	(243)	42
Accrued taxes	61	29	(165)
Accrued compensation and benefits	29	5	(22)
Other current liabilities	56	69	54
Cash collateral, net	(116)	140	(54)
Other	137	148	48
Net cash provided from operating activities	3,371	3,447	2,713
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,976	1,311	4,528
Short-term borrowings, net	975	—	—
Redemptions and Repayments-			
Long-term debt	(2,331)	(879)	(1,759)
Short-term borrowings, net	—	(91)	(1,605)
Common stock dividend payments	(611)	(607)	(604)
Other	(31)	(13)	(47)
Net cash (used for) provided from financing activities	(22)	(279)	513
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,835)	(2,704)	(3,312)

Nuclear fuel	(232)	(190)	(233)
Proceeds from asset sales	15	20	394
Sales of investment securities held in trusts	1,678	1,534	2,133
Purchases of investment securities held in trusts	(1,789)	(1,648)	(2,236)
Asset removal costs	(145)	(142)	(153)
Other	27	8	48
Net cash used for investing activities	(3,281)	(3,122)	(3,359)
Net change in cash and cash equivalents	68	46	(133)
Cash and cash equivalents at beginning of period	131	85	218
Cash and cash equivalents at end of period	$199	$131	$85
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: stock contribution to pension plan	$500	$—	$—
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$1,050	$1,028	$931
Income taxes (received), net of refunds	$(16)	$37	$(103)

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

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

	For the Years Ended December 31		
(In millions)	2016	2015	2014
STATEMENTS OF INCOME (LOSS)			
REVENUES:			
Electric sales to non-affiliates	$3,781	$4,153	$5,114
Electric sales to affiliates	457	664	861
Other	160	188	169
Total revenues*	4,398	5,005	6,144
OPERATING EXPENSES:			
Fuel	780	871	1,253
Purchased power from affiliates	624	353	271
Purchased power from non-affiliates	1,020	1,684	2,771
Other operating expenses	1,277	1,308	1,635
Pension and OPEB mark-to-market adjustment	48	57	297
Provision for depreciation	336	324	319
General taxes	88	98	128
Impairment of assets (Note 2)	8,622	33	—
Total operating expenses	12,795	4,728	6,674
OPERATING INCOME (LOSS)	(8,397)	277	(530)
OTHER INCOME (EXPENSE):			
Investment income (loss)	67	(14)	61
Miscellaneous income	7	3	6
Interest expense — affiliates	(7)	(7)	(7)
Interest expense — other	(147)	(147)	(152)
Capitalized interest	34	35	34
Total other expense	(46)	(130)	(58)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(8,443)	147	(588)
INCOME TAXES (BENEFITS)	(2,988)	65	(228)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(5,455)	82	(360)
Discontinued operations (net of income taxes of $70) (Note 20)	—	—	116
NET INCOME (LOSS)	$(5,455)	$82	$(244)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)			
NET INCOME (LOSS)	$(5,455)	$82	$(244)

OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(14)	(6)	(6)
Amortized gains on derivative hedges	—	(3)	(10)
Change in unrealized gain on available-for-sale securities	52	(9)	21
Other comprehensive income (loss)	38	(18)	5
Income taxes (benefits) on other comprehensive income (loss)	15	(7)	2
Other comprehensive income (loss), net of tax	23	(11)	3
COMPREHENSIVE INCOME (LOSS)	$(5,432)	$71	$(241)

*Includes excise tax collections of $28 million, $44 million and $69 million in 2016, 2015 and 2014, respectively.

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $5 in 2016 and $8 in 2015	213	275
Affiliated companies	452	451
Other, net of allowance for uncollectible accounts of $0 in 2016 and $3 in 2015	27	59
Notes receivable from affiliated companies	29	11
Materials and supplies	267	470
Derivatives	137	154
Collateral	157	70
Prepayments and other	63	66
	1,347	1,558
PROPERTY, PLANT AND EQUIPMENT:		
In service	7,057	14,311
Less — Accumulated provision for depreciation	5,929	5,765
	1,128	8,546
Construction work in progress	427	1,157
	1,555	9,703
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,552	1,327
Other	10	10
	1,562	1,337
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	9	61
Goodwill	—	23
Accumulated deferred income taxes	2,279	—
Property taxes	40	40
Derivatives	77	79
Other	372	367
	2,777	570
	$ 7,241	$ 13,168
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 179	$ 512
Short-term borrowings-		
Affiliated companies	101	—
Other	—	8
Accounts payable-		
Affiliated companies	550	542
Other	110	139
Accrued taxes	143	76
Derivatives	77	104

Other	156	181
	1,316	1,562
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding as of December 31, 2016 and 2015	3,658	3,613
Accumulated other comprehensive income	69	46
Retained earnings (Accumulated deficit)	(3,509)	1,946
Total common stockholder's equity	218	5,605
Long-term debt and other long-term obligations	2,813	2,510
	3,031	8,115
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	757	791
Accumulated deferred income taxes	—	600
Retirement benefits	197	332
Asset retirement obligations	901	831
Derivatives	52	38
Other	987	899
	2,894	3,491
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16)		
	$ 7,241	$ 13,168

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock Number of Shares	Common Stock Carrying Value	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
Balance, January 1, 2014	7	$ 3,080	$ 54	$ 2,178
Net loss				(244)
Amortized loss on derivative hedges, net of $4 million of income tax benefits			(6)	
Change in unrealized gain on investments, net of $8 million of income taxes			13	
Pension and OPEB, net of $2 million of income tax benefits (Note 4)			(4)	
Equity contribution from parent		500		
Stock-based compensation		7		
Consolidated tax benefit allocation		7		
Balance, December 31, 2014	7	3,594	57	1,934
Net income				82
Amortized loss on derivative hedges, net of $1 million of income tax benefits			(2)	
Change in unrealized gain on investments, net of $4 million of income tax benefits			(5)	
Pension and OPEB, net of $2 million of income tax benefits (Note 4)			(4)	
Stock-based compensation		10		
Consolidated tax benefit allocation		9		
Cash dividends declared on common stock				(70)
Balance, December 31, 2015	7	3,613	46	1,946
Net loss				(5,455)
Change in unrealized gain on investments, net of $20 million of income taxes			32	
Pension and OPEB, net of $5 million of income tax benefits (Note 4)			(9)	
Inter-company asset transfer (Note 14)		28		
Stock-based compensation		9		
Consolidated tax benefit allocation		8		
Balance, December 31, 2016	7	$ 3,658	$ 69	$ (3,509)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31 2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$(5,455)	$82	$(244)
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel, intangible assets and deferred debt-related costs	633	579	615
Investment impairments	19	90	33
Pension and OPEB mark-to-market adjustment	48	57	297
Deferred income taxes and investment tax credits, net	(2,920)	119	7
Deferred costs on sale and leaseback transaction, net	49	48	48
Impairment of assets	8,622	33	—
Pension trust contribution	(138)	—	—
Gain on investment securities held in trusts	(48)	(24)	(61)
Commodity derivative transactions, net (Note 11)	9	(74)	65
Lease payments on sale and leaseback transaction	(120)	(131)	(131)
Income from discontinued operations (Note 20)	—	—	(116)
Change in current assets and liabilities-			
Receivables	89	277	674
Materials and supplies	26	(25)	(44)
Prepayments and other current assets	(8)	14	14
Accounts payable	(30)	(76)	(477)
Accrued taxes	76	(26)	(50)
Other current liabilities	15	43	(18)
Cash collateral, net	(87)	159	(92)
Other	5	6	51
Net cash provided from operating activities	785	1,151	571
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	471	341	878
Short-term borrowings, net	101	—	