FIRSTENERGY CORP
Form 10-K
February 20, 2018

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, 2017

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 per share	New York Stock Exchange

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

Registrant	Title of 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 (§229.405 of this chapter) 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, a smaller reporting company, or emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth 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
Emerging Growth Company o	N/A

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o
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., $12,919,874,051 as of June 30, 2017; and for FirstEnergy Solutions Corp., none.
Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF JANUARY 31, 2018
FirstEnergy Corp., $0.10 par value	475,589,829
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 2018 Annual Meeting of Shareholders of FirstEnergy Corp. to be held May 15, 2018	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 attributable 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) of 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. These risks, unless otherwise indicated, are presented on a consolidated basis for FirstEnergy; if and to the extent a deconsolidation occurs with respect to certain FirstEnergy companies the risks described herein may materially change. 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, a subsidiary of FirstEnergy Corp.
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
BU Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply, and 50% owner in a joint venture that owns the Buchanan Generating Facility
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
FENOC	FirstEnergy Nuclear Operating Company, a subsidiary of FE, 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
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, which owns and operates 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
Signal Peak	Signal Peak Energy, LLC, an indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

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

AAA	American Arbitration Association
ADIT	Accumulated Deferred Income Taxes

GLOSSARY OF TERMS, Continued

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
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
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
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DMR	Distribution Modernization Rider
DOE	United States Department of Energy
DPM	Distribution Platform Modernization
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 Units
ELPC	Environmental Law & Policy Center
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency

EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
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
Facebook®	Facebook is a registered trademark of Facebook, Inc.

GLOSSARY OF TERMS, Continued

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
HCl	Hydrochloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	Intercontinental Exchange, Inc.
ICP 2007	FirstEnergy Corp. 2007 Incentive Plan
ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan
IIP	Investment Infrastructure Program
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
kW	Kilowatt
KWH	Kilowatt-hour
LBR	Little Blue Run
LED	Light Emitting Diode
LOC	Letter of Credit
LSE	Load Serving Entity
LS Power	LS Power Equity Partners, LP
LTIIPs	Long-Term Infrastructure Improvement Plans
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.
MOPR	Minimum Offer Price Rule
MVP	Multi-Value Project
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJAPA	New Jersey Administrative Procedure Act
NJBPU	New Jersey Board of Public Utilities
NOL	Net Operating Loss
NOPR	Notice of Proposed Rulemaking
NOV	Notice of Violation
NOx	Nitrogen Oxide

NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NS	Norfolk Southern Corporation
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission

GLOSSARY OF TERMS, Continued

OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
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
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
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
RWG	Restructuring Working Group
S&P	Standard & Poor’s Ratings Service
SB310	Substitute Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SIP	State Implementation Plan(s) Under the Clean Air Act
Sixth Circuit	United States Court of Appeals for the Sixth Circuit

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

GLOSSARY OF TERMS, Continued

SSO	Standard Service Offer
Tax Act	Tax Cuts and Jobs Act adopted December 22, 2017
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
Twitter®	Twitter is a registered trademark of Twitter, Inc.
UWUA	Utility Workers Union of America
VEPCO	Virginia Electric and Power Company
VIE	Variable Interest Entity
VMP	Vegetation Management Plan
VMS	Vegetation Management Surcharge
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 incorporated under Ohio law 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, MAIT 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 over six million customers in the Midwest and Mid-Atlantic regions. Its regulated and unregulated generation subsidiaries control over 16,000 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 24,500 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), and 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, MAIT and TrAIL).

Unregulated Competitive Subsidiaries

FES, a subsidiary of FE, was incorporated under Ohio law 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, which are operated by FENOC. FG, a subsidiary of FES, was organized under Ohio law in 2000. FG sells the entire output of its fossil generating facilities (5,440 MWs) to FES. NG was organized under Ohio law 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 Ohio law in 1998.

AE Supply was organized under Delaware law in 1999. AE Supply provides energy-related products and services primarily to wholesale customers. AE Supply also owns and operates the Pleasants generating facility (1,300 MWs), and owns approximately 59% of AGC and a 50% interest in the Buchanan Generating facility.

AGC was organized under Virginia law in 1981. Approximately 59% of AGC is owned by AE Supply and approximately 41% is owned 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.

AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC’s interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments. On December 13, 2017, AE Supply completed the sale of its four natural gas generating plants and expects to complete the sale of approximately 59% of AGC’s interest in the Bath County hydroelectric power station and BU Energy’s 50% interest in the Buchanan Generating facility in the first half of 2018. For additional information, see "Competitive Generation Asset Sale" below.

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.

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 Ohio law 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 Pennsylvania law in 1930 and owns property and does business as an electric public utility in that state. Penn is also authorized to do business in 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 Ohio law 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 Ohio law 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 New Jersey law 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 Pennsylvania law in 1917 and owns property and does business as an electric public utility in that state. ME provides 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 Pennsylvania law in 1919 and owns property and does business as an electric public utility in that state. PN provides 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 Maryland law in 1923 and under Virginia law in 1974. PE is authorized to do business in Virginia, 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 Ohio law 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, 2017, 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.

WP was organized under Pennsylvania law 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, NERC, and their respective state regulatory authorities (PUCO, PPUC, NJBPU, WVPSC, MDPSC, NYPSC, and VSCC).

Transmission Subsidiaries

ATSI was organized under Ohio law 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 Maryland law and Virginia law 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 VEPCO 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 Delaware law 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 4,234 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 at cost, in accordance with its cost allocation manual, 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, TrAIL, MAIT (effective January 31, 2017) and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP). 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 "Utility Regulation - FERC Matters," below, MAIT and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. In March 2017, FERC approved JCP&L's and MAIT's forward-looking formula rates, subject to refund, with effective dates of June 1, 2017, and July 1, 2017, respectively. Additionally, MAIT and JCP&L filed settlement agreements with FERC on October 13, 2017 and December 21, 2017, respectively, both pending final orders by FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under forward-looking rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which are subject to an annual true-up based on actual costs. 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, Maryland, Michigan, New Jersey and Illinois, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. As of January 31, 2018, this business segment controlled 12,303 MWs of electric generating capacity, including, as discussed in "Unregulated Competitive Subsidiaries" above, 756 MWs of generating capacity which remain subject to an asset purchase agreement with a subsidiary of LS Power that is expected to close in the first half of 2018. 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.

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, 2017, Corporate/Other had $6.8 billion of stand-alone holding company long-term debt, of which $1.45 billion was subject to variable-interest rates, and $300 million was borrowed by FE under its revolving credit facility. On January 22, 2018, FE repaid its $1.45 billion of outstanding variable-interest rate debt using the proceeds from the $2.5 billion equity investment.

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 January 31, 2018, FirstEnergy's competitive generating portfolio consists of 12,303 MWs of electric generating capacity. Of the competitive generation asset portfolio, approximately 6,136 MWs (49.9%) consist of coal-fired capacity; 4,048 MWs (32.9%) consist of nuclear capacity; 713 MWs (5.8%) consist of hydroelectric capacity; 733 MWs (6.0%) consist of oil and natural gas units; 496 MWs (4.0%) consist of wind and solar power arrangements; and 177 MWs (1.4%) 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 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 2,123 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 agreed to sell to a subsidiary of LS Power 1,615 MWs of electric generating capacity. On December 13, 2017, AE Supply completed the sale of its four natural gas generating plants (859 MWs). The sale of the remaining 756 MWs of generating capacity is expected to close in the first half of 2018. FES' generating facilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's generating facilities are primarily located in West Virginia, Virginia and Ohio.

On January 10, 2018, a fire damaged the scrubber, stack and other plant property and systems associated with Bruce Mansfield Units 1 and 2. Evaluation of the extent of the damage, which may be significant, to the scrubber, stack and other plant property and systems associated with Units 1 and 2 is underway and is expected to take several weeks. Unit 3, which had been off-line for maintenance, was unaffected by the fire. The affected plant property and systems are insured and management is working with the insurance carriers to complete the assessment. At this time management is unable to estimate the financial effect of the fire on Units 1 and 2.

In November 2016, FirstEnergy announced a strategic review to exit its commodity-exposed generation at CES, which is primarily comprised of the operations of FES and AE Supply. In connection with this strategic review, AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC’s interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments and through multiple, independent closings. On December 13, 2017, AE Supply completed the sale of the natural gas generating plants with net proceeds, subject to post-closing adjustments, of approximately $388 million. The sale of AE Supply’s interests in the Bath County hydroelectric power station and the Buchanan Generating facility is expected to generate net proceeds of $375 million and is anticipated to close in the first half of 2018, subject in each case to various customary and other closing conditions, including, without limitation, receipt of regulatory approvals.

Additionally, on March 6, 2017, AE Supply and MP entered into an asset purchase agreement for MP to acquire AE Supply’s Pleasants Power Station (1,300 MWs) for approximately $195 million, resulting from an RFP issued by MP to address its generation shortfall. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC’s affiliate cross-subsidization analysis. On January 26, 2018, the WVPSC approved the transfer of the Pleasants Power Station, subject to certain conditions as further described in "West Virginia Regulatory Matters," below, which included MP assuming significant commodity risk. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement and on February 16, 2018, AE Supply announced its intent to exit operations of the Pleasants Power Station by January 1, 2019, through either sale or deactivation, which resulted in a pre-tax impairment charge of $120 million.

With the sale of the gas plants completed, upon the consummation of the sale of AGC's interest in the Bath County hydroelectric power station or the sale or deactivation of the Pleasants Power Station, AE Supply is obligated under the amended and restated purchase agreement and AE Supply's applicable debt agreements, to satisfy and discharge approximately $305 million of currently outstanding senior notes as well as its $142 million of pollution control notes and AGC’s $100 million senior notes, which are expected to require the payment of “make-whole” premiums currently estimated to be approximately $95 million based on current interest rates. For additional information see "Outlook" below.

The strategic options to exit the remaining portion of the CES portfolio, which is primarily at FES, are limited. The credit quality of FES, including its unsecured debt rating of Ca at Moody’s, C at S&P, and C at Fitch and the negative outlook from Moody’s and S&P, has challenged its ability to consummate asset sales. Furthermore, the inability to obtain legislative support under the Department of Energy’s recent NOPR, which was rejected by FERC, limits FES’ strategic options to plant deactivations, restructuring its debt and other financial obligations with its creditors, and/or to seek protection under U.S. bankruptcy laws.

As part of the strategic review, FES evaluated its options with respect to its nuclear power plants. Factors considered as part of this review included current and forecasted market conditions, such as wholesale power and capacity prices, legislative and regulatory solutions that recognize their environmental and energy security benefits, and many other factors, including the significant capital and operating costs associated with operating a safe and reliable nuclear fleet. Based on this analysis, given the weak power and capacity price environment and the lack of legislative and regulatory solutions achieved to date, FES concluded that it would be increasingly difficult to operate these facilities in this environment and absent significant change concluded that it was probable that the facilities would be either deactivated or sold before the end of their estimated useful lives. As a result, FES recorded a pre-tax charge of $2.0 billion in the fourth quarter of 2017 to fully impair the nuclear facilities, including the generating plants and nuclear fuel as well as to reserve against the value of materials and supplies inventory and to increase its asset retirement obligation. For additional information see Note 2, "Asset Sales and Impairments."

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of January 31, 2018, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. As previously disclosed, FES has $515 million of maturing debt in 2018 (excluding intra-company debt), beginning with a $100 million principal payment due April 2, 2018. Based on FES' current senior unsecured debt rating, capital structure and long-term cash flow projections, the debt maturities are unlikely to be refinanced. Although management continues to explore cost reductions and other options to improve cash flow, these 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.

Regulated Generation

As of January 31, 2018, 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 Yard's 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 an RFP to address its generation shortfall previously identified in the IRP filed with the WVPSC. The IRP identified a capacity shortfall for MP starting in 2016 and exceeding 700 MWs by 2020 and 850 MWs by 2027. AE Supply was the winning bidder of the RFP to address MP’s generation shortfall and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire AE Supply’s Pleasants Power Station (1,300 MW). As discussed in "Competitive Generation," above, based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement.

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, Maryland, Michigan, New Jersey and Illinois, 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.

Following the adoption of the Tax Act, various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities’ rates and charges. State proceedings which have arisen are discussed below. The Utilities continue to monitor and investigate the impact of state regulatory impacts resulting from the Tax Act.

Federal Regulation

With respect to their wholesale services and rates, the Utilities, AE Supply, ATSI, AGC, FES, FG, MAIT, NG 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, MAIT, MP, PE, WP and TrAIL to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of ATSI, JCP&L, MAIT, 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.

To date, FERC has yet to issue guidance to address how to reflect the impacts resulting from the Tax Act in customer rates. Management continues to monitor and investigate the impact of changes to federal regulation resulting from the Tax Act.

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 certain of 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 certain of 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 certain of 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 certain of 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 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 certain of its subsidiaries, AE Supply, FENOC, ATSI, MAIT 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, MAIT 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, MAIT 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, MAIT and TrAIL continue to collect cost-based rates for their transmission and distribution services; accordingly, it is appropriate that the Utilities, AGC, ATSI, MAIT 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.

As a result of the Tax Act, FirstEnergy adjusted its net deferred tax liabilities at December 31, 2017, for the reduction in the corporate income tax rate from 35% to 21%. For the portions of FirstEnergy’s business that apply regulatory accounting, the impact of reducing the net deferred tax liabilities was offset with a regulatory liability, as appropriate, for amounts expected to be refunded to rate payers in future rates, with the remainder recorded to deferred income tax expense.

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. 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 achieved under PE's current plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER Maryland program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. The costs of PE's 2015-2017 plan approved by the MDPSC in December 2014 were approximately $60 million. PE filed its 2018-2020 EmPOWER Maryland plan on August 31, 2017. The 2018-2020 plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. On December 22, 2017, the MDPSC issued an order approving the 2018-2020 plan with various modifications. PE recovers 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 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. Comments were filed and a hearing was held in late 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. On January 19, 2018, PE filed a joint petition, along with other utility companies, work group stakeholders, and the MDPSC electric vehicle work group leader, to implement a statewide electric vehicle portfolio. If approved, PE will launch an electric vehicle charging infrastructure program on January 1, 2019, offering up to 2,000 rebates for electric vehicle charging equipment to residential customers, and deploying up to 259 chargers at non-residential customer service locations at a projected total cost of $12 million. PE is proposing to recover program costs subject to a five-year amortization. On February 6, 2018, the MDPSC opened a new proceeding to consider the petition and directed that comments be filed by March 16, 2018.

On January 12, 2018, the MDPSC instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of Maryland utilities. PE must track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and submitted a report to the MDPSC on February 15, 2018, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers and proposed to file a base rate case in the third quarter of 2018 where the benefits from the effects of the Tax Act will be realized by customers through a lower rate increase than would otherwise be necessary.

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.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended 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. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L’s 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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 included 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, 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 Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On December 19, 2017, the NJBPU approved the issuance of proposed rules to modify the CTA methodology consistent with its October 22, 2014 Generic Order. The proposed rule was published in the NJ Register on January 16, 2018, and was republished on February 6, 2018, to correct an error. Interested parties have sixty days to comment on the proposed rulemaking.

At the December 19, 2017 NJBPU public meeting, the NJBPU approved its IIP rulemaking. The IIP creates a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety. JCP&L expects to make a filing in 2018.

On January 31, 2018, the NJBPU instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of New Jersey utilities. JCP&L must track and apply regulatory accounting treatment for the impacts effective January 1, 2018, and file a petition with the NJBPU by March 2, 2018, regarding the expected impacts of the Tax Act on JCP&L's expenses and revenues and how the effects will be passed through to its customers.

Ohio Regulatory Matters

The Ohio Companies currently operate under ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO's Opinion and Order issued on March 31, 2016 and Fifth Entry on Rehearing on 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. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $204 million annually. Revenues from 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 $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: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016, and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates (which filing was made on April 3, 2017, and remains pending).

Several parties, including the Ohio Companies, filed applications for rehearing regarding 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 August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies' challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO's August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the Ohio Manufacturer's Association Energy Group filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. On November 16, 2017, the Ohio Companies intervened in the appeal. Additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various

PUCO entries on their applications for rehearing. For additional information, see “FERC Matters - Ohio ESP IV PPA,” below.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. 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 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. 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. On November 21, 2017, the PUCO issued an order that approved the filed Stipulation and Recommendation with several modifications, including a cap on the Ohio Companies’ collection of program costs and shared savings set at 4% of the Ohio Companies’ total sales to customers as reported on FERC Form 1. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO’s modification of the Stipulation and Recommendation to include the 4% cost cap, which was denied by the PUCO on January 10, 2018.

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 that in 2014 SB310 froze 2015 and 2016 requirements at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. 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. The OCC and the ELPC also filed appeals of the PUCO's order. On January 24, 2018, the Supreme Court of Ohio reversed the PUCO order finding that the order violated the rule against prohibiting retroactive ratemaking. On February 5, 2018, the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition on February 15, 2018.

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. On March 29, 2017, the PUCO issued a Second Entry on Rehearing that granted, in part, the applications for rehearing filed by FES and other parties, finding that the PUCO’s guidelines regarding fixed-price contracts should not apply to large mercantile customers. This finding changes the original order, which applied the guidelines to all customers, including mercantile customers. The PUCO also reaffirmed several provisions of the original order, including that the fixed-price guidelines only apply on a going-forward basis and not to existing contracts and that regulatory-out clauses in contracts are permissible.

On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan. The DPM Plan is a portfolio of approximately $450 million in distribution platform investment projects, which are designed to modernize the Ohio Companies’ distribution grid, prepare it for further grid modernization projects, and provide customers with immediate reliability benefits. The Ohio Companies have requested that the PUCO issue an order approving the DPM Plan and associated cost recovery no later than May 2, 2018, so that the Ohio Companies can expeditiously commence the DPM Plan and customers can begin to realize the associated benefits.

On January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act and determine the appropriate course of action to pass benefits on to customers. The Ohio Companies must establish a regulatory liability, effective January 1, 2018, for the estimated reduction in federal income tax resulting from the Tax Act, and filed comments on February 15, 2018, explaining that customers will save nearly $40 million annually as a result of updating tariff riders for the tax rate changes and that the Ohio Companies’ base distribution rates are not impacted by the Tax Act changes because they are frozen through May 2024.

Pennsylvania Regulatory Matters

The Pennsylvania Companies operate under 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 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. The DSPs include modifications to the Pennsylvania Companies' POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

On December 11, 2017, the Pennsylvania Companies filed DSPs for the June 1, 2019 through May 31, 2023 delivery period. Under the 2019-2023 DSPs, the supply is proposed to be provided by wholesale suppliers through a mix of 3, 12 and 24-month energy contracts, as well as two RFPs for 2-year SREC contracts for ME, PN and Penn. The 2019-2023 DSPs as proposed also include modifications to the Pennsylvania Companies' POR programs in order to continue their clawback pilot program as a long-term, permanent program term. The 2019-2023 DSPs also introduce a retail market enhancement rate mechanism designed to stimulate residential customer shopping, and modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW. A hearing has been scheduled for April 10-11, 2018, and the PPUC is expected to issue a final order on these DSPs by mid-September 2018.

The Pennsylvania Companies operate under rates that were approved by the PPUC on January 19, 2017, effective as of January 27, 2017. These rates provide annual increases in operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are intended to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements.

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. 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 February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the remaining period of 2018 to 2020, as modified, are: WP $50.1 million; PN $44.8 million; Penn $33.2 million; and ME $51.3 million.

On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery, which were approved by the PPUC on June 9, 2016, and went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. On January 19, 2017, in the PPUC’s order approving the Pennsylvania Companies’ general rate cases, the PPUC added an additional issue to the DSIC proceeding to include whether ADIT should be included in DSIC calculations. On February 2, 2017, the parties to the DSIC proceeding submitted a Joint Settlement to the ALJ that resolved the issues that were pending from the order issued on June 9, 2016, which is pending PPUC approval. The ADIT issue is subject to further litigation and a hearing was held on May 12, 2017. On August 31, 2017, the ALJ issued a decision recommending that the complaint of the Pennsylvania OCA be granted by the PPUC such that the Pennsylvania Companies reflect all federal and state income tax deductions related to DSIC-eligible property in the currently effective DSIC rates. If the decision is approved by the PPUC, the impact is not expected to be material to FirstEnergy. The Pennsylvania Companies filed exceptions to the decision on September 20, 2017, and reply exceptions on October 2, 2017.

On February 12, 2018, the PPUC initiated a proceeding to determine the effects of the Tax Act on the tax liability of utilities and the feasibility of reflecting such impacts in rates charged to customers. By March 9, 2018, the Pennsylvania Companies must submit information to the PPUC to calculate the net effect of the Tax Act on income tax expense and rate base, and comments addressing whether rates should be adjusted to reflect the tax rate changes, and if so, how and when such modifications should take effect.

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 September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of 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. On December 15, 2017, the WVPSC approved MP's and PE's proposed annual decrease in their EE&C rates, effective January 1, 2018, which is not material to FirstEnergy.

On December 9, 2016, the WVPSC approved the annual ENEC case for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, resulting in an increase in the ENEC rate of $25 million annually beginning January 1, 2017. In addition, ENEC rates will be maintained at the same level for a two year period.

On December 30, 2015, MP and PE 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. On December 16, 2016, MP issued an RFP to address its generation shortfall, 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. AE Supply was the winning bidder of the RFP to address MP’s generation shortfall and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire AE Supply’s Pleasants Power Station (1,300 MWs) for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals. In addition, on March 7, 2017, MP and PE filed an application with the WVPSC and MP and AE Supply filed an application with FERC requesting authorization for such purchase. Various intervenors filed protests challenging the RFP and requesting FERC deny the application, set it for hearing to allow discovery into the RFP process, or delay an order pending the conclusion of the WVPSC proceeding. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate that the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC’s affiliate cross-subsidization analysis. In the order FERC also revised and clarified certain details of its standards for the review of transactions resulting from competitive solicitations, and concluded that MP’s RFP did not meet the revised and clarified standards. FERC allowed that MP may submit a future application for a transaction resulting from a new RFP.

The WVPSC issued its order on January 26, 2018, denying the petition as filed but granting the transfer of Pleasants Power Station under certain conditions, which included MP assuming significant commodity risk. MP, PE and AE Supply have determined not to seek rehearing at FERC in light of the adverse decisions at FERC and the WVPSC. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement. With respect to the Bath County RFP, MP does not plan to move forward with that sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

On September 1, 2017, MP and PE filed with the WVPSC for a reconciliation of their VMS to confirm that rate recovery matches VMP costs and for a regular review of that program. MP and PE proposed a $15 million annual decrease in VMS rates effective January 1, 2018, and an additional $15 million decrease in rates for 2019. This is an overall decrease in total revenue and average rates of 1%. On December 15, 2017, the WVPSC issued an order adopting a unanimous settlement without modification.

On January 3, 2018, the WVPSC initiated a proceeding to investigate the effects of the Tax Act on the revenue requirements of utilities. MP and PE must track the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018, and file written testimony explaining the impact of the Tax Act on federal income tax and revenue requirements by May 30, 2018. On January 26, 2018, the WVPSC issued an order clarifying that regulatory accounting should be implemented as of January 1, 2018, including the recording of any regulatory liabilities resulting from the Tax Act.

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, but subsequently agreed to suspend it and advised FERC of this course of action.

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. On August 30, 2017, the generation owners requested expedited action by FERC. 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. FirstEnergy and certain of the other parties responded to such opposition. On October 20, 2017, the settling and non-opposing parties requested expedited action by FERC. 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, ATSI resolved a dispute regarding responsibility for certain costs for the “Michigan Thumb” transmission project. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. 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. The MISO TOs subsequently filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened and participated in the proceedings on behalf of ATSI, the Ohio Companies and Penn. On June 21, 2017, the Sixth Circuit issued its decision denying the MISO TOs' appeal request. MISO and the MISO TOs did not seek review by the U.S. Supreme Court, effectively resolving the dispute over the "Michigan Thumb" transmission project. 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 MVP costs and "legacy RTEP" transmission projects cannot be predicted at this time.

Transfer of Transmission Assets to MAIT

Following receipt of necessary regulatory approvals, on January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and transmission asset contributions. MAIT, a transmission-only subsidiary of FET, owns and operates all of the FERC-jurisdictional transmission assets previously owned by ME and PN. Subsequently, on March 13, 2017, FERC issued an order authorizing MAIT to issue short- and long-term debt securities, permitting MAIT to participate in the FirstEnergy regulated companies’ money pool for working capital, to fund day-to-day operations, support capital investment and establish an actual capital structure for ratemaking purposes.

MAIT Transmission Formula Rate

On October 28, 2016, as amended on January 10, 2017, 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 February 1, 2017. 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. On March 10, 2017, FERC issued an order accepting the MAIT formula transmission rate for filing, suspending the formula transmission rate for five months to become effective July 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, MAIT requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. MAIT’s rates went into effect on July 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC. The settlement agreement provides for certain changes to MAIT's formula rate, changes MAIT's ROE from 11% to 10.3%, sets the recovery amount for certain regulatory assets, and establishes that MAIT's capital structure will not exceed 60% equity over the period ending December 31, 2021. The settlement agreement further provides that the ROE and the 60% cap on the equity component of MAIT's capital structure will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2022. The settlement agreement currently is pending at FERC. As a result of the settlement agreement, MAIT recognized a pre-tax impairment charge of $13 million in the third quarter of 2017.

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. 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 March 10, 2017, FERC issued an order accepting the JCP&L formula transmission rate for filing, suspending the transmission rate for five months to become effective June 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, JCP&L requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. JCP&L’s rates went into effect on June 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On December 21, 2017, JCP&L and certain parties filed a settlement agreement with FERC. The settlement agreement provides for a $135 million stated annual revenue requirement for Network Integration Transmission Service and an average of $20 million stated annual revenue requirement for certain projects listed on the PJM Tariff where the costs are allocated in part beyond the JCP&L transmission zone within the PJM Region. The revenue requirements are subject to a moratorium on additional revenue requirements proceedings through December 31, 2019, other than limited filings to seek recovery for certain additional costs. Also on December 21, 2017, JCP&L filed a motion for authorization to implement the settlement rate on an interim basis. On December 27, 2017, FERC granted the motion authorizing JCP&L to implement the settlement rate effective January 1, 2018, pending a final commission order on the settlement agreement. The settlement agreement is pending at FERC. As a result of the settlement agreement, JCP&L recognized a pre-tax impairment charge of $28 million in the fourth quarter of 2017.

DOE NOPR: Grid Reliability and Resilience Pricing

On September 28, 2017, the Secretary of Energy released a NOPR requesting FERC to issue rules directing RTOs to incorporate pricing for defined “eligible grid reliability and resiliency resources” into wholesale energy markets. Specifically, as proposed, RTOs would develop and implement tariffs providing a just and reasonable rate for energy purchases from eligible grid reliability and resiliency resources and the recovery of fully allocated costs and a fair ROE. The NOPR followed the August 23, 2017, release of the DOE’s study regarding whether federally controlled wholesale energy markets properly recognize the importance of coal and nuclear plants for the reliability of the high-voltage grid, as well as whether federal policies supporting renewable energy sources have harmed the reliability of the energy grid. The DOE requested for the final rules to be effective in January 2018.

On October 2, 2017, FERC established a docket and requested comments on the NOPR. FESC and certain of its affiliates submitted comments and reply comments. On January 8, 2018, FERC issued an order terminating the NOPR proceeding, finding that the NOPR did not satisfy the statutory threshold requirements under the FPA for requiring changes to RTO/ISO tariffs to address resilience concerns. FERC in its order instituted a new administrative proceeding to gather additional information regarding resilience issues, and directed that each RTO/ISO respond to a provided list of questions. There is no deadline or requirement for FERC to act in this new proceeding. At this time, we are uncertain as to the potential impact that final action by FERC, if any, would have on FES and our strategic options, and the timing thereof, with respect to the competitive business.

Competitive Generation Asset Sale

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments and through multiple, independent closings. On December 13, 2017, AE Supply completed the sale of the natural gas generating plants with net proceeds, subject to post-closing adjustments, of approximately $388 million. The sale of AE Supply's interests in the Bath County hydroelectric power station and the Buchanan Generating facility is expected to generate net proceeds of $375 million and is anticipated to close in the first half of 2018, subject in each case to various customary and other closing conditions, including, without limitation, receipt of regulatory approvals.

As part of the closing of the natural gas generating plants, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement.

With the sale of the gas plants completed, upon the consummation of the sale of AGC's interest in the Bath County hydroelectric power station or the sale or deactivation of the Pleasants Power Station, AE Supply is obligated under the amended and restated purchase agreement and AE Supply's applicable debt agreements to satisfy and discharge approximately $305 million of currently outstanding senior notes, as well as its $142 million of pollution control notes and AGC's $100 million senior notes, which are expected to require the payment of "make-whole" premiums currently estimated to be approximately $95 million based on current interest rates.

On October 20, 2017, the parties filed an application with the VSCC for approval of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station. On December 12, 2017, FERC issued an order authorizing the partial transfer of the related hydroelectric license for Bath County under Part I of the FPA. In December 2017, AGC, AE Supply and MP filed with FERC and AGC and AE Supply filed with the VSCC, applications for approval of AGC redeeming AE Supply’s shares in AGC upon consummation of the Bath County transaction. On February 2, 2018, the VSCC issued an order finding that approval of the proposed stock redemption is not required, and on February 16, 2018, FERC issued an order authorizing the redemption. Upon the consummation of the redemption, AGC will become a wholly-owned subsidiary of MP.

On December 28, 2017, FERC issued an order authorizing the sale of BU Energy’s Buchanan interests. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once the sales are consummated. There can be no assurance that all regulatory approvals will be obtained and/or all closing conditions will be satisfied or that the remaining transactions will be consummated.

As a result of the amended asset purchase agreement, CES recorded non-cash pre-tax impairment charges of $193 million in 2017, reflecting the $825 million purchase price as well as certain purchase price adjustments based on timing of the closing of the transaction.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. 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 hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017, and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC, seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers commented on the compliance filing, alleging inaccuracies in and lack of transparency of data and information in the compliance filing, and requested that PATH be directed to recalculate the refund provided in the filing. PATH responded to these comments in a filing that was submitted on May 22, 2017. On July 27, 2017, FERC Staff issued a letter to PATH requesting additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH filed its response on September 27, 2017. FERC orders on PATH's requests for rehearing and compliance filing remain pending.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and certain of its subsidiaries, Buchanan Generation and Green Valley 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 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. On July 27, 2017, FERC accepted the triennial filing as submitted.

Capital Requirements

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.

On January 22, 2018, FirstEnergy announced a $2.5 billion equity issuance, which included $1.62 billion in mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The preferred shares will receive the same dividend paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The new preferred shares contain an optional conversion for holders beginning in July 2018, and will mandatorily convert in 18-months from the issuance, subject to limited exceptions. Proceeds from the investment were used to reduce holding company debt by $1.45 billion and fund the company’s pension plan by $750 million, with the remainder used for general corporate purposes.

The equity investment allows FirstEnergy to strengthen its balance sheet and supports the company's transition to a fully regulated utility company. By deleveraging the company, the investment will also enable FirstEnergy to enhance its investment grade credit metrics and FirstEnergy does not currently anticipate the need to issue additional equity through at least 2021 outside of its regular stock investment and employee benefit plans.

In addition to this equity investment, 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 2018 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 may be met through the issuance of long-term debt at certain utility and transmission subsidiaries to, among other things, fund capital expenditures and 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, an unregulated companies' money pool (which also includes FE, FET, FEV and certain other unregulated subsidiaries of FE but excludes FENOC, FES and its subsidiaries) and proceeds generated from previously disclosed asset sales, subject to closing, and in the case of FES, its current access to a separate unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, and a two-year secured line of credit from FE of up to $500 million, as further described below.

FES subsidiaries have debt maturities of $515 million in 2018, (excluding intra-company debt), beginning with a $100 million principal payment due April 2, 2018. Based on FES' current senior unsecured debt rating, capital structure and long-term cash flow projections, the debt maturities are unlikely to be refinanced. Although management continues to explore cost reductions and other options to improve cash flow, these 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. Furthermore, the inability to obtain legislative support under the Department of Energy's recent NOPR, which was rejected by FERC, limits FES' strategic options to plant deactivations, restructuring its debt and other financial obligations with its creditors, and/or to seek protection under U.S. bankruptcy laws.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed 2017 funding obligations 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 January 2018, FirstEnergy satisfied its minimum required funding obligations of $500 million and, as discussed above, addressed funding obligations for future years to its qualified pension plan with additional contributions of $750 million.

FirstEnergy's capital expenditures for 2018 are expected to be approximately $2.6 billion to $2.9 billion, excluding CES. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

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

Reportable Segment	2017 Actual[1]	2017 Pension/OPEB Mark-to-Market Capital Adjustment	2017 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2018 Forecast[2]
	(In millions)			
Regulated Distribution	$1,342	$ (20)	$ 1,362	$1,500 - $1,600
Regulated Transmission	1,032	1	1,031	1,000 - 1,200
CES	279	(1)	280	— [3]
Corporate/Other	99	—	99	100
Total	$2,752	$ (20)	$ 2,772	$2,600 - $2,900

(1) Includes a decrease of approximately $20 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) Planned capital expenditures will be dependent on the outcome of the strategic review of CES.

Additionally, planned capital expenditures for Regulated Distribution includes $1.4 billion to $1.7 billion, annually, 2019 through 2021, while planned capital expenditures for Regulated Transmission are expected to be approximately $1.0 billion to $1.2 billion, annually, 2019 through 2021.

Capital expenditures for 2017 and 2018 forecast by subsidiary are included in the following table.

Operating Company	2017 Actual[1]	2017 Pension/OPEB Mark-to-Market Capital Adjustment	2017 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2018 Forecast[2][3]
	(In millions)			
OE	$143	$ (12)	$ 155	$ 160
Penn	55	(1)	56	45
CEI	134	4	130	145
TE	37	(3)	40	50
JCP&L	317	3	314	380
ME	142	(4)	146	185
PN	162	(12)	174	195
MP	269	9	260	280
PE	112	—	112	150
WP	199	(2)	201	260
ATSI	541	—	541	375
TrAIL	45	—	45	55
FES	250	(3)	253	— [4]
AE Supply	34	2	32	— [4]
MAIT	242	(1)	243	400
Other subsidiaries	70	—	70	70
Total	$2,752	$ (20)	$ 2,772	$ 2,750

(1) Includes a decrease of approximately $20 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) 2018 Forecast represents the mid-point of Regulated Distribution and Regulated Transmission's 2018 forecasted capital expenditures.
(4) Planned capital expenditures will be dependent on the outcome of the strategic review of CES.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the Energizing the Future transmission plan, pursuant to which FirstEnergy plans to invest $4.0 to $4.8 billion in capital investments from 2018 to 2021, with $4.4 billion in capital investment 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. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,500 mile transmission system, making this a continuing platform for investment in the years beyond 2021.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2017, 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.

	2018	2019-2022	Total
	(In millions)		
FirstEnergy	$1,051	$ 6,008	$7,059

FES	$515	$ 1,948	$2,463

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The following table displays consolidated operating lease commitments as of December 31, 2017.

Operating Leases	FirstEnergy	FES
	(In millions)	
2018	$146	$101
2019	128	97
2020	102	68
2021	124	93
2022	111	91
Years thereafter	1,263	1,131
Total minimum lease payments	$1,874	$1,581

FE and the Utilities and FET and its subsidiaries participate in two separate five-year syndicated revolving credit facilities with aggregate commitments of $5.0 billion (Facilities), which are available through December 6, 2021. FE and the Utilities and FET and its subsidiaries may use borrowings under their Facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt-to-total-capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

FirstEnergy had $300 million and $2,675 million of short-term borrowings as of December 31, 2017 and 2016, respectively. FirstEnergy’s available liquidity from external sources as of January 31, 2018 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	December 2021	$4,000	$ 3,740
FET[(2)]	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 4,740
		Cash	—	358
		Total	$5,000	$ 5,098

(1) FE and the Utilities. Available liquidity includes impact of $10 million of LOCs issued under various terms.
(2) Includes FET, ATSI, MAIT and TrAIL.

FES had $105 million and $101 million of short-term borrowings as of December 31, 2017 and December 31, 2016, respectively. Of such amounts, $102 million and $101 million, respectively, represents a currently outstanding promissory note due April 2, 2018, payable to AE Supply with any additional short-term borrowings representing borrowings under an unregulated companies' money pool, which also includes FE, FET, FEV and certain other unregulated subsidiaries of FE, but excludes FENOC, FES and its subsidiaries. In addition to FES' access to a separate unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, FES' available liquidity as of January 31, 2018, was as follows:

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

Cash	—	1
	$ 500	$ 501

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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, 2017, FirstEnergy had approximately $2.7 billion (FES $1.9 billion) invested in external trusts to be used for the decommissioning and environmental remediation of its nuclear generating facilities. The values of FirstEnergy's NDTs also fluctuate based on market conditions. If the values 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.

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. In 2017, FENOC commenced a multi-year effort to implement repairs to the shield building. In addition to these ongoing repairs, FENOC intends to submit a license amendment application to the NRC to reconcile the shield building laminar cracking concern.

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. So long as FES remains in the unregulated companies' money pool, the $500 million secured line of credit with FE discussed above provides FES the needed liquidity in order for FES to satisfy its nuclear support obligations to NG.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.4 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $450 million; and (ii) $13.0 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 and NG's maximum potential assessment under these provisions would be $509 million per incident but not more than $76 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 yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.4 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. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition.

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 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 the EPA’s regulatory approach under CSAPR, but questioning whether the EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. The 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. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, the EPA’s reconsideration of the CSAPR update rule and how the EPA and the states ultimately 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. The EPA missed the October 1, 2017, deadline and has not yet promulgated the attainment designations. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. On December 5, 2017, fourteen states and the District of Columbia filed complaints in the U.S. District Court of Northern California seeking an order that the EPA promulgate the attainment designations for 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, but has not taken any further action. On January 2, 2018, the State of Delaware provided the EPA a notice required at least 60 days prior to filing a suit seeking to compel the EPA to either approve or deny the August 2016 CAA Section 126 petition. 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, but has not taken any further action. On September 27, 2017, and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the

U.S. District Court for the District of Maryland seeking an order that the EPA either approve or deny the CAA Section 126 petition of November 16, 2016. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

MATS imposed emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired EGUs effective in April 2015 with averaging of emissions from multiple units located at a single plant. The majority of FirstEnergy's MATS compliance program and related costs have been completed.

On August 3, 2015, FG, a wholly owned 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 arose 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. 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 hearing in November and December 2016. On April 12, 2017, the arbitration panel ruled on liability in favor of BNSF and CSX. In the liability award, the panel found, among other things, that FG’s demand for declaratory judgment that force majeure excused FG’s performance was denied, that FG breached and repudiated the coal transportation contract and that the panel retains jurisdiction of claims for liquidated damages for the years 2015-2025. On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to this consolidated proceeding on the terms and conditions set forth below. Pursuant to the settlement agreement, FG will pay CSX and BNSF an aggregate amount equal to $109 million, which is payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provides that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. Further, FE and FG, and CSX and BNSF, agreed to release, waive and discharge each other from any further obligations under the claims covered by the settlement agreement upon payment in full of the settlement amount. Until such time, CSX and BNSF will retain the claims covered by the settlement agreement and in the event of a bankruptcy proceeding with respect to FG, to the extent the remaining settlement payments are not paid in full by FG or FE, CSX and BNSF shall be entitled to seek damages for such claims in an amount to be determined by the arbitration panel or otherwise agreed by the parties.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS which 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 generating station. 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 liquidated damages through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. The arbitration hearing is scheduled for June 2018. The parties have exchanged settlement proposals to resolve all claims related to this proceeding, however, discussions have been terminated and settlement is unlikely. FirstEnergy and FES recorded a pre-tax charge of $116 million in 2017 based on an estimated range of losses regarding the ongoing litigation with respect to this agreement. If the case proceeds to arbitration, the amount of damages owed to BNSF and NS could be materially higher and may cause FES to seek protection under U.S. bankruptcy laws. FG intends to vigorously assert its position in this arbitration proceeding, and 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.

As to a specific coal supply agreement, AE Supply, the party thereto, asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, on January 15, 2015, Tunnel Ridge, LLC, the coal supplier, commenced litigation in the Court of Common Pleas of Allegheny County, Pennsylvania, alleging AE Supply did not have sufficient justification to terminate the agreement and seeking damages for the difference between the market and contract price of the coal, or lost profits plus incidental damages. AE Supply filed an answer denying any liability related to the termination. On May 1, 2017, the complaint was amended to add FE, FES and FG, although not parties to the underlying contract, as defendants and to seek additional damages based on new claims of fraud, unjust enrichment, promissory estoppel and alter ego. On June 27, 2017, after oral argument, defendants' preliminary objections to the amended complaint were denied. On February 18, 2018, the parties reached an agreement in principle settling all claims in dispute. The agreement in principle includes, among other matters, a $93 million payment by AE Supply, as well as certain coal supply commitments for Pleasants Power Station during its remaining operation by AE Supply. Certain aspects of the final settlement agreement will be guaranteed by FE, including the $93 million payment.

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, the 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, the 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 U.S. 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 CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel-fired EGUs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired EGUs. Numerous states and private parties filed appeals and motions to stay the CPP with 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. On March 28, 2017, an executive order, entitled “Promoting Energy Independence and Economic Growth,” instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, 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 GHG emissions by 26 to 28 percent below 2005 levels by 2025 and in September 2016, 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 became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. 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. Depending on any final action taken by the states with respect to impingement and entrainment, 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 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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. 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 CCRs, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, 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. The Sierra Club's Notices of Appeal before the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility were resolved through a Consent Adjudication between FG, PA DEP and the Sierra Club requiring operational changes that became effective November 3, 2017.

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, 2017, 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 $125 million have been accrued through December 31, 2017. Included in the total are accrued liabilities of approximately $80 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

Fuel Supply

FirstEnergy currently has coal contracts with various terms to acquire approximately 16 million tons of coal (FES 8 million tons) for the year 2018, which is approximately 97% of its forecasted 2018 coal requirements. This contracted coal is produced primarily from mines located in 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.

FENOC 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 2028 and Davis-Besse through 2024 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 Unit 2. Davis-Besse resumed 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 potential 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 waste, 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, FES has made arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

System Demand

The maximum hourly demand for each of the Utilities was:

System Demand	2017	2016	2015
	(in MWs)		
OE	5,434	5,655	5,391
Penn	926	994	983
CEI	4,220	4,193	4,057
TE	2,205	2,171	2,149
JCP&L	5,721	5,955	5,789
ME	2,897	2,904	2,770
PN	2,882	2,890	3,024
MP	1,986	2,053	2,031
PE	3,049	3,049	3,631
WP	3,752	3,947	3,942

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 the default 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, ATSI, MAIT and TrAIL 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, 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.

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Executive Officers as of February 20, 2018

Name	Age	Positions Held During Past Five Years	Dates
G. D. Benz	58	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	*-2015
D. M. Chack	67	Senior Vice President, Product Development, Marketing and Branding (B)	2017-present
		Senior Vice President, Marketing and Branding (B)	2015-2017
		President, Ohio Operations (B)	*-2015
		Vice President (C)	*-2015
M. J. Dowling	53	Senior Vice President, External Affairs (B)	*-present
B. L. Gaines	64	Senior Vice President, Corporate Services and Chief Information Officer (B)	*-present
C. E. Jones	62	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
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	63	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)	*-2015
R. P. Reffner	67	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
S. E. Strah	54	President (G)	2017-present
		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	44	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)	*-2013
L. L. Vespoli	58	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
E. L. Yeboah-Amankwah	40	Vice President, Corporate Secretary and Chief Ethics Officer (A)(B)	2017-present
		Vice President, State and Federal Regulatory Legal Affairs (B)	2017
		Vice President and Corporate Secretary (C)(D)(G)(H)(I)(L)(N)	2017-present

* Indicates position held at least since January 1, 2013	(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, 2017, FirstEnergy had 15,617 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	4,944	893
OE	1,141	745
CEI	915	594
TE	334	244
Penn	185	131
JCP&L	1,358	1,047
ME	661	487
PN	750	475
FES	56	—
FG	687	499
FENOC	2,328	1,028
MP	1,045	690
PE	499	307
WP	714	459
Total	15,617	7,599

As of December 31, 2017, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 6,604 of FirstEnergy's employees. There are 22 CBAs between FirstEnergy's subsidiaries and its unions, which have three, four or five year terms. In 2017, certain of FirstEnergy's subsidiaries reached new agreements on CBAs with three different UWUA locals, covering approximately 1,073 employees. Additionally, in 2017, agreements were reached with two IBEW locals, covering approximately 711 employees.

- On January 5, 2017, UWUA Local 180, which represents approximately 123 employees in PN, ratified a new agreement that will expire August 31, 2022.
- On March 2, 2017, IBEW Local 777, which represents approximately 497 employees in ME, ratified a contract that will expire on April 30, 2022.
- On May 18, 2017, IBEW Local 272, which represents approximately 214 employees at the Bruce Mansfield Plant, ratified a new agreement that will expire on February 15, 2020.
- On October 10, 2017, UWUA Local 304, which represents approximately 164 employees at the Harrison Plant, ratified a new agreement that will expire March 1, 2022.
- On October 27, 2017, UWUA Local 270, which represents approximately 786 employees at CEI, the Perry nuclear plant and the Eastlake synchronous condenser plant, ratified a new agreement that will expire on April 30, 2022.

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 and Current Reports on Form 8-K, and FE's proxy statements and amendments to those documents 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. These risks, unless otherwise indicated, are presented on a consolidated basis for FirstEnergy; if and to the extent a deconsolidation occurs with respect to certain FirstEnergy companies, the risks described herein may materially change. Additional information on risk factors is included in "Item 1. Business," and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," 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 or other filings seeking cost recovery for distribution system enhancements in the states where our Utilities operate and transmission rate filings at FERC. 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.

Failure to Successfully Implement Strategic Alternatives for the CES Segment to Exit the Competitive Generation Business May Further Negatively and Materially Impact the Future Results of Operations and Financial Condition of FirstEnergy and FES

Weak wholesale energy and capacity markets with significantly low results from recent capacity auctions and anemic demand forecasts have lowered the value of the business and continue to challenge the CES segment, including FES. Consequently, as previously disclosed, FirstEnergy is engaged in a strategic review of its competitive operations including the pending sale of certain AE Supply generation assets, and FES is exploring all alternatives for its generation assets.

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) restructuring FES debt with its creditors, and/or (iii) seeking protection under U.S. bankruptcy laws for FES and FENOC. Management anticipates that the viability of these alternatives will be determined in the near term. 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 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, Have a Material Adverse Effect on Results of Operations and the Financial Condition of FE and FES and Cause FES and FENOC, to Take Other Actions, Including Debt Restructuring or Seeking Protection under the U.S. Bankruptcy Laws

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:

- the inability to refinance debt maturities at FES subsidiaries of $515 million and $323 million in 2018 and 2019, respectively, at attractive rates or at all;

- requests to post additional collateral or accelerate payments, including prepayments to certain trade creditors; and
- adverse outcomes in previously disclosed disputes regarding long-term coal and coal transportation contracts.

Even if the alternatives outlined above or any other viable business alternatives are implemented, any one of these events or other further adverse developments in the CES segment 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 FENOC may determine to seek protection under U.S. bankruptcy laws regardless of the viability of one or more strategic alternatives.

Any such developments could have important consequences, including:

- the risk that we may not be able to, or may no longer desire to, complete our planned disposition of our generating assets;
- the risk that FirstEnergy could be required to satisfy or otherwise elect to guarantee significant financial obligations of FES or its subsidiaries, which could adversely affect the financial condition and cash flows of FirstEnergy;
- the risk that creditors of FES may attempt to assert claims, including those that arise out of litigation or other commercial disputes, against FirstEnergy that may require significant effort and money to defend and could adversely affect the business, financial condition, results of operations and cash flows of FirstEnergy; and
- the risk that certain triggering events could constitute events of default under certain of FirstEnergy's obligations.

Additionally, a deactivation significantly prior to the applicable license expiration date of one or more of NG's 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 with respect to the applicable unit, thus requiring financial guarantees or additional contributions, which could be significant. The funds from the NDTs may also 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 debt-to-total-capitalization ratio included in FE's credit facility excludes 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, the asset impairments recognized in 2016 fully utilized the $5.5 billion exclusion and charges beyond that amount will negatively impact the debt-to-total-capitalization covenant, 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 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 significantly low prices in the wholesale energy and capacity markets, weak demand for electricity and anemic demand forecasts along with the inability to obtain legislative or regulatory relief, FES' cash flow from operations may be insufficient to repay its indebtedness or trade payables in the near- and long-term. FES' near-term 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.

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. Due to FES' financial condition, there is a substantial risk that it may be necessary for FES and 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 fully draw down its $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.

FES' Inability to Satisfy its Financial Obligations Could Require FirstEnergy to Make Substantial Payments in Respect of such Obligations, which Could Adversely Affect the Financial Condition, Cash Flows, and the Ability to Satisfy Obligations of FirstEnergy

FE has provided a revolving credit agreement to FES that permits borrowings of up to $500 million and provides additional credit support to FES of up to $200 million. As part of FirstEnergy's centralized cash management functions, FES, its subsidiaries and FENOC have the ability to borrow from each other and FE to meet their short-term working capital requirements. In addition, FE has guaranteed certain material financial obligations of FES and its subsidiaries. FirstEnergy also could elect to assume or satisfy other material financial obligations of FES and its subsidiaries. It is also possible that creditors of FES may attempt to assert claims against FirstEnergy that may require significant effort and money to defend or could result in losses to FirstEnergy. There can be no assurance that FirstEnergy would be successful in defending against any such claims. Any of these matters could adversely affect the financial condition, cash flows and ability to satisfy obligations of FirstEnergy. In addition, the uncertainty associated with these matters could adversely affect FirstEnergy’s ability to access the capital or credit markets and ability to finance its business.

Adverse Developments Related to the CES Segment Could Trigger Events of Default under Certain FirstEnergy Obligations

FirstEnergy's credit facilities contain various events of default, including with respect to the borrowers or significant subsidiaries (each as defined in the credit agreements), a bankruptcy or insolvency, the failure to pay any principal of or premium or interest on any indebtedness in excess of $100 million, or the failure to satisfy any judgment or order for the payment of money exceeding any applicable insurance coverage by more than $100 million. Although FES and its subsidiaries are not “significant subsidiaries” for these purposes, it is possible that an adverse development related to FES could trigger an event of default under the FirstEnergy credit facilities if creditors of FES asserted successful claims against FE or our significant subsidiaries. Additionally, although the debt-to-total-capitalization ratio covenant included in FirstEnergy's credit facility excludes 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, the asset impairments recognized in 2016 fully utilized the $5.5 billion exclusion and charges beyond that amount will negatively impact the debt-to-total-capitalization covenant. Any development, such as the bankruptcy or insolvency of FirstEnergy subsidiaries, debt acceleration or failures to satisfy judgments, could adversely affect the liquidity of FirstEnergy.

In the Event of a Foreclosure, Liquidation, Bankruptcy or Similar Proceeding Involving FES, FG or NG, the Value of the Collateral Securing the Secured Indebtedness of FES’ Subsidiaries May Not be Sufficient to Ensure Repayment of Such Indebtedness and, in the Case of a Bankruptcy Proceeding, the Ability of Holders of Such Indebtedness, Including FE, to Realize Any such Value May be Delayed or Otherwise Limited

FG and NG have secured pollution control notes outstanding as of December 31, 2017 of $612.2 million (FG - $327.6 million of FMBs; NG - $284.6 million of FMBs) and secured obligations supporting FES’ $500 million revolving line of credit and $200 million additional credit support with FE (FG - $250 million of FMBs; NG - $450 million of FMBs). In the event of a foreclosure, liquidation, bankruptcy or similar proceeding affecting FES, FG or NG or any of their respective properties or assets, the value of the collateral securing such indebtedness or the net proceeds from any sale or liquidation of such collateral, as applicable, may not be sufficient to pay the obligations under such secured indebtedness. If the value of the collateral or the net proceeds of any sale of such collateral, as applicable, are not sufficient to repay all amounts due with respect to such secured indebtedness, the holders of the secured indebtedness would have an unsecured claim for the deficiency in value or proceeds against the applicable obligors alongside all other unsecured creditors of such obligor. None of FG, NG or FES can assure holders of their respective secured debt that, if a sale process were to be pursued, the collateral will be saleable or, if saleable, that there will not be substantial delays in its liquidation due to, among other things, the need for regulatory authorization from the FERC, NRC or other governmental authorities, as applicable.

Additionally, in the context of a bankruptcy case by or against FES, FG or NG, the holders of the secured indebtedness may not be able or entitled to receive payment of interest, fees (including attorney’s fees), costs or charges related to such secured obligations, and may be required to repay any such amounts received by such holders during such bankruptcy case.

The value of the collateral securing FG’s and NG’s secured obligations is subject to fluctuation and will depend on market and other economic conditions, including the availability of any suitable buyers for the collateral, which could be impacted by the risks and costs associated with operating nuclear generation facilities in the case of NG’s properties and the risks and costs of operating coal and other fossil-fueled generation facilities in the case of FG’s properties, including, in each case, complying with federal, state and local statutes and regulations associated with public health and safety and the environment.

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. Any such sale may be difficult to implement due to current and anticipated future market conditions and the attractiveness of nuclear and coal facilities to prospective purchasers. Additionally, 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, AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC’s interest in Bath County (1,615 MWs of combined capacity), each component of which may close separately, for an aggregate all-cash purchase price of $825 million, subject to adjustments.

While the sale of the four natural gas generating plants was completed on December 13, 2017, the sale of AE Supply's interest in the Buchanan Generating facility and AGC's interest in Bath County remain pending and are expected to close in the first half of 2018, subject to, in each case, various customary and other closing conditions including, without limitation, receipt of regulatory approvals.

If the above sales or any 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. There can be no assurance that all closing conditions will be satisfied or that such sales will be consummated.

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 a Bankruptcy Proceeding by FES and/or FENOC

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies pursuant to transactions involving credit, 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, legal settlements 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 related to certain operating expenses and requirements. 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.

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. In the event FES seeks protection under U.S. bankruptcy laws, it is expected FENOC will similarly seek protection under U.S. bankruptcy laws. 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 or FENOC bankruptcy proceeding. FirstEnergy is unable to estimate the outcome of such challenges or other claims arising out of an FES or FENOC 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.

FES and FG are exposed to losses under the sale and leaseback arrangement for Unit 1 at the Bruce Mansfield plant upon the occurrence of certain contingent events that could render that facility worthless such as a casualty event. FES and FG have a maximum exposure to loss under those provisions of approximately $1.1 billion.

On the morning of January 10, 2018, Bruce Mansfield plant personnel were in the process of shutting down Unit 1 for a maintenance outage when an equipment failure resulted in an unplanned outage for Unit 2 that led to the loss of plant power. Later that morning, a fire damaged the scrubber, stack and other plant property and systems associated with Units 1 and 2. Evaluation of the extent of the damage, which may be significant, to the scrubber, stack and other plant property and systems associated with Units 1 and 2, and whether it may trigger a loss under the sale and leaseback arrangement, is underway and is expected to take several weeks.

As part of AE Supply's recent sale of gas generation assets to a subsidiary of LS Power, FE provided two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC arising under the purchase agreement. Liabilities incurred under these guarantees could have an adverse impact on FE.

Risks Related to the CES Segment

Continued Low 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 Including the Ongoing Strategic Review of Competitive Operations

Long-term low 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 weakness of these markets may further negatively and materially impact the future results of operations and financial condition of FirstEnergy and FES and may limit the ability of FES to sell these units to third parties.

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, FES has liquidity support through the secured credit facility entered into between FES and FE in December 2016 and an unregulated companies’ money pool, through which FE expects to provide ongoing liquidity to FES and its subsidiaries through March 2018. AE Supply has access to a separate unregulated companies' money pool. No assurance can be given, however, that such expectations will not change or that the strategic alternatives for CES 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, 2017, $2.8 billion of outstanding long-term debt, of which approximately $610 million is secured and approximately $2.2 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 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, including:

- difficulty satisfying debt service and other obligations at FES and/or its individual subsidiaries;
- the unlikelihood of FG and NG being able to refinance debt maturities of $515 million and $323 million in 2018 and 2019, respectively;
- additional postings of collateral or acceleration of payments;
- increasing the vulnerability of the business of FES to adverse industry and economic conditions;
- reducing the availability of FES cash flow to fund other corporate purposes; and
- reducing the ability of FES to enter into transactions with counterparties due to demands for additional collateral or credit support due to FES' creditworthiness.

If market conditions in the wholesale energy and capacity markets continue to be weak and the strategic alternatives described above 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 of all 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, it is likely FENOC will 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 which may, among other things, result in cross defaults of other FES debt obligations. These defaults would have a material adverse effect on FirstEnergy’s and FES' business, financial condition, results of operations and liquidity.

Disruptions in Fuel Supplies and Changes in Fuel Transportation Needs Could Adversely Affect Relationships With Suppliers, the Ability to Operate Generation Facilities or Lead to Business Disputes and Material Judgments, Any of Which May Adversely Impact Financial Results, and in the Case of a Certain Fuel Transportation Contract, an Adverse Resolution 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

CES purchases 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 fuel suppliers, could cause an adverse impact on the ability to operate CES' generating facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect results of operations of FirstEnergy and FES.

Operation of CES' coal-fired generation facilities is highly dependent on its ability to procure coal. CES has long-term contracts in place for a majority of its coal supply and transportation needs, one of which runs through 2028 and certain of which relate to deactivated plants. For example, AE Supply and FG have asserted force majeure defenses for delivery shortfalls under certain of these agreements relating to our deactivated plants. One such agreement which is currently in arbitration relates to the transportation of an aggregate of a minimum of 2.5 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, AE Supply has also asserted termination rights effective in 2015 and is in litigation with the counterparty.

No assurance can be provided 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 the financial condition and results of operations of FirstEnergy and FES, and in the case of the arbitration related to the fuel transportation contract discussed above, an adverse resolution 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, it is expected FENOC will similarly seek protection under U.S. bankruptcy laws.

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

During the period of FirstEnergy’s transition to a fully regulated company away from commodity exposed generation, CES continues to purchase and sell electricity in the competitive retail and wholesale markets. Increases in the costs of fuel for generation facilities (particularly coal, uranium and natural gas) may affect CES’ 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 generation facilities, may impact the results of operations and financial position of FirstEnergy and FES by decreasing sales margins or increasing the amount paid to purchase power to satisfy sales obligations in the states in which CES does business. CES is exposed to risk from the volatility of the market price of natural gas. Its 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 CES realizes from sales will be lower and, on occasion, CES 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.

CES Is Exposed to Price Risks Associated With Marketing and Selling Products in the Power Markets That It Does Not Always Completely Hedge Against

CES purchases and sells power at the wholesale level under market-based rate tariffs authorized by FERC, and also enters into agreements to sell available energy and capacity from its generation assets. If CES is unable to deliver firm capacity and energy under these agreements, it 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 CES' ability to meet its obligations, or cause increases in the market price of replacement capacity and energy.

CES attempts to mitigate risks associated with satisfying its contractual power sales arrangements by reserving generation capacity to deliver electricity to satisfy its net firm sales contracts and, when necessary, by purchasing firm transmission service. CES also routinely enters into contracts, such as fuel and power purchase and sale commitments, to hedge exposure to fuel requirements and other energy-related commodities. CES may not, however, hedge the entire exposure of its operations from commodity price volatility. To the extent CES does not hedge against commodity price volatility, the results of operations and financial position of FirstEnergy and FES 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 FES or AE Supply's 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 the Business, Results of Operations and Financial Condition of FirstEnergy and FES

FES is 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 FES' 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 FES' 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 those of FES. Also, a serious nuclear incident at one of FES' nuclear facilities or a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit. Any one of these risks relating to FES' nuclear generation could have a material adverse effect on the business, results of operations and financial condition of FirstEnergy and FES.

There Are Uncertainties Relating to 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 the Results of Operations and Cash Flows and Financial Condition of FirstEnergy and FES

RTO rules could affect the ability to sell energy and capacity produced by CES' generating facilities to users in certain markets. The rules governing the various regional power markets may change from time to time, which could affect its costs or revenues. In some cases, these changes are contrary to its interests and adverse to its 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 CES' generating assets currently participate in PJM, which conducts RPM auctions for capacity on an annual planning year basis. The prices CES can charge for its 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. CES cannot predict the outcome of future auctions, but if the auction prices are sustained at low levels, the results of operations, financial condition and cash flows of FirstEnergy and FES could be adversely impacted.

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

As a member of an RTO, CES is 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 reforms. 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 a Certain Fuel Transportation Contract, an Adverse Decision 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. 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 a certain coal transportation contract, such an unfavorable result 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, it is expected FENOC will 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 58% 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. 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 and could require our coal-fired generation plants to curtail generation or cease to generate. 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 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.

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 an Adverse Impact on Our Results of Operations and Financial Condition and Demand Significantly Below or Above Our Forecasts Could Adversely Affect Our Energy Margins and Have an Adverse Effect on our Financial Condition and Results of Operations

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 Industries such as Shale Gas, 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. 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.

FirstEnergy recognizes as a pension and 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 depend on 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, legal claims or proceedings, 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 $4.0 to $4.8 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 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 even 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's outstanding principal balance is $275 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 $275 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. Various parties have appealed the PUCO’s denial of subsequent applications for rehearing to the Ohio Supreme Court. 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 and Restrictions and Prohibitions on Certain Business Dealings Could Have a Negative Impact on Our Business, Financial Condition, Results of Operations and Cash Flows

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 a material adverse impact on our results of operations.

Our transmission and operating utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may be decreased as a result of actions taken by FERC or by a state regulatory commission in which the Utilities 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. 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.

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 subsidiaries 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 financial 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.

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, in December 2017, Congress passed the Tax Act. Details regarding the transition from the current tax code to new tax reforms are only beginning to emerge. We cannot predict whether, when or to what extent new tax regulations, interpretations or rulings will be issued, nor is the long-term impact of proposed tax reform clear. The 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 and our transmission-owning affiliates, FirstEnergy cannot predict what, if any, response state regulatory commissions or FERC may have and the potential response of such authorities regarding the rates and charges of the Utilities and our transmission-owning affiliates.

The EPA is Conducting NSR Investigations at 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 from changing or conflicting interpretations of existing laws and regulations, including, for example, the applicability of the 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 during work considered by the companies to be routine maintenance. The 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 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 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 cannot directly recover through rates additional costs incurred for such deregulated generation facilities. 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 in September 2016, joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. However, on June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the 2015 Paris Agreement. 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.

We Could be Exposed to Private Rights of Action Relating to Environmental Matters Seeking Damages Under Various State and Federal Law Theories Which Could Have an Adverse Impact on Our Results of Operations, Financial Condition and Business Operations

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 business 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. Depending on the 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 Environmental Liabilities, Including Costs of Remediation of Environmental Contamination at Current or Formerly Owned Facilities, Which Could Have a Material Adverse effect on Our Results of Operations and Financial Condition

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.

The Risks Associated with Climate Change May Have an Adverse Impact on Our Business Operations, Operating Results 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 business operations, operating results and cash flows. 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.

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. 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.

Our Mandatorily Convertible Preferred Stock Will be Converted into Common Stock, at the Latest, in Two Years from the Date of Issuance and the Holders Thereof Have Registration Rights. Upon Conversion of the Preferred Shares, the Number of Common Shares Eligible for Future Resale in the Public Market Will Increase and May Result in Dilution to Common Shareholders. This May Have an Adverse Effect on the Market Price of Common Stock.

On January 22, 2018, FE issued $2.5 billion of equity, which included $1.62 billion of mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The issuance of common equity created some dilution to existing common holders. The new preferred shares contain an optional conversion for holders beginning in July 2018, and will mandatorily convert in 18 months from issuance, subject to limited exceptions.

Upon the conversion of the mandatorily convertible preferred stock additional shares of our common stock will be issued, which results in dilution to our stockholders, and will increase the number of shares eligible for resale in the public market. Sales of substantial numbers of such shares in the public market could adversely affect the market price of our common stock.

We Cannot Assure Common and Preferred 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 or preferred 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. Further, the terms of the outstanding preferred stock require that preferred shareholders receive dividends alongside the common shareholders on an as-converted, pro rata basis.

The Recognition of Impairments of Goodwill and Long-Lived Assets Has Adversely Affected 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, 2017. 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.

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 debt-to-total-capitalization ratio of FE’s credit facility excludes 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, the asset impairments recognized in 2016 fully utilized the $5.5 billion exclusion and charges beyond that amount will negatively impact the debt-to-total-capitalization covenant, which may 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 January 31, 2018, 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.

Plant (Location)	Unit	Total		Competitive FES	Competitive 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	(9)	—	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	(7)	1,010	—		—
Bay Shore (Toledo, OH)	1	136	(7)	136	—		—
OVEC (Cheshire, OH) (Madison, IN)	1-11	188	(2)	110	67		11
		1,334		1,256	67		11
Nuclear:							
Beaver Valley (Shippingport, PA)	1	939		939	—		—
Beaver Valley (Shippingport, PA)	2	933		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:							
West Lorain (Lorain, OH)	1-6	545		545	—		—
Forked River (Ocean County, NJ)	2	86		86	—		—
Buchanan (Oakwood, VA)	1-2	43	(3)	—	43	(8)	—
Other		59		59	—		—

		733		690	43		—
Pumped-storage Hydro:							
Bath County (Warm Springs, VA)	1-6	1,200	(4)	—	713	(8)	487
Yard's Creek (Blairstown Twp., NJ)	1-3	210	(5)	—	—		210
		1,410		—	713		697
Wind and Solar Power		496	(6)	496	—		—
Total		16,093		10,180	2,123		3,790

(1) Includes FE's leasehold interest of 93.83% (779 MWs) from non-affiliates.
(2) Represents FES' 4.85%, AE Supply's 3.01% and MP's 0.49% entitlement based on their participation in OVEC.
(3) Represents BU Energy's 50% interest. BU Energy is a subsidiary of AE Supply.
(4) Represents AGC's 40% undivided interest in Bath County. The station is operated by VEPCO. AGC is 59% owned by AE Supply and 41% owned by MP.
(5) Represents JCP&L's 50% ownership interest.
(6) Includes 167 MWs from leased facilities and 329 MWs under power purchase agreements.
(7) On July 22, 2016, FirstEnergy and FES announced its intent to exit operations of the Bay Shore Unit 1 generating station by October 1, 2020, through either sale or deactivation and to deactivate Units 1-4 of the W. H. Sammis generating station by May 31, 2020.
(8) Subject to an asset purchase agreement with a subsidiary of LS Power, expected to close in the first half of 2018.
(9) On February 16, 2018, AE Supply announced its intent to sell or deactivate the Pleasants Power Station by January 1, 2019.

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 24,493 circuit miles.

The Utilities' electric distribution systems include 276,555 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 164,470,215 kV-amperes.

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

FirstEnergy's distribution and transmission systems as of December 31, 2017, consist of the following:

	Distribution Lines(1)	Transmission Lines(1)	Substation Transformer Capacity(2) kV Amperes
OE	67,194	378	7,924,723
Penn	13,605	—	1,033,407
CEI	33,473	—	10,174,280
TE	19,048	73	2,916,453
JCP&L	23,555	2,598	23,505,921
ME	18,929	—	5,160,600
PN	27,623	—	9,059,288
ATSI(3)	—	7,808	38,895,189
WP	25,008	4,339	16,016,116
MP	22,324	2,653	12,206,638
PE	25,796	2,149	11,256,764
TrAIL	—	261	13,130,600
MAIT	—	4,234	13,190,236
Total	276,555	24,493	164,470,215

(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, "Selected Financial Data."

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 2017.

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,	2017	2016	2015	2014	2013
	(In millions, except per share amounts)				
Revenues	$14,017	$14,562	$15,026	$15,049	$14,892
Income (Loss) From Continuing Operations	$(1,724)	$(6,177)	$578	$213	$375
Earnings (Loss) Available to FirstEnergy Corp.	$(1,724)	$(6,177)	$578	$299	$392
Earnings (Loss) per Share of Common Stock:					
Basic - Continuing Operations	$(3.88)	$(14.49)	$1.37	$0.51	$0.90
Basic - Discontinued Operations	—	—	—	0.20	0.04
Basic - Earnings (Loss) Available to FirstEnergy Corp.	$(3.88)	$(14.49)	$1.37	$0.71	$0.94
Diluted - Continuing Operations	$(3.88)	$(14.49)	$1.37	$0.51	$0.90
Diluted - Discontinued Operations	—	—	—	0.20	0.04
Diluted - Earnings (Loss) Available to FirstEnergy Corp.	$(3.88)	$(14.49)	$1.37	$0.71	$0.94
Weighted Average Shares Outstanding:					
Basic	444	426	422	420	418
Diluted	444	426	424	421	419
Dividends Declared per Share of Common Stock	$1.44	$1.44	$1.44	$1.44	$1.65
Total Assets	$42,257	$43,148	$52,094	$51,552	$49,980
Capitalization as of December 31:					
Total Equity	$3,925	$6,241	$12,422	$12,422	$12,695
Long-Term Debt and Other Long-Term Obligations	21,115	18,192	19,099	19,080	15,753
Total Capitalization	$25,040	$24,433	$31,521	$31,502	$28,448

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.

	2017		2016	
	High	Low	High	Low
First Quarter	$32.54	$29.51	$36.54	$30.62
Second Quarter	$31.94	$27.93	$36.32	$31.37
Third Quarter	$33.08	$28.93	$36.60	$32.12
Fourth Quarter	$35.22	$30.18	$34.83	$29.33
Yearly	$35.22	$27.93	$36.60	$29.33

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2012 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 79,916 and 79,454 holders of 445,334,111 and 475,589,829 shares of FE's common stock as of December 31, 2017 and January 31, 2018, 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 and readers are cautioned not to place undue reliance on these forward-looking statements. 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 and the effectiveness of our strategy to transition to a fully regulated business profile.
- The accomplishment of our regulatory and operational goals in connection with our transmission and distribution investment plans, including, but not limited to, our planned transition to forward-looking formula rates.
- 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.
- Success of legislative and regulatory solutions for generation assets that recognize their environmental or energy security benefits.
- The risks and uncertainties associated with the lack of viable alternative strategies regarding the CES segment, thereby causing FES to restructure its substantial debt and other financial obligations with its creditors or seek protection under U.S. bankruptcy laws (which filing would include FENOC) 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, its subsidiaries, and FENOC, related to wholesale energy and capacity markets, and the viability and/or success of strategic business alternatives, such as pending and potential CES generating unit asset sales or the potential need to deactivate additional generating units, which could result in further substantial write-downs and impairments of assets.
- The substantial uncertainty as to FES' ability to continue as a going concern and substantial risk that it may be necessary for FES and 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 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, margins and operations 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.

- 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, including the federal administration's required review and potential revision of 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).
- 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, including the Tax Act, 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 FES and its subsidiaries.
- 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 and thereby on FE's preferred 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. These risks, unless otherwise indicated, are presented on a consolidated basis for FirstEnergy; if and to the extent a deconsolidation occurs with respect to certain FirstEnergy companies, the risks described herein may materially change. 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. Each of the registrants expressly disclaims any obligation to update or revise, 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.

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	1,049
Penn	Western Pennsylvania	166
CEI	Northeastern Ohio	751
TE	Northwestern Ohio	311
JCP&L	Northern, Western and East Central New Jersey	1,127
ME	Eastern Pennsylvania	569
PN	Western Pennsylvania and Western New York	587
WP	Southwest, South Central and Northern Pennsylvania	726
MP	Northern, Central and Southeastern West Virginia	392
PE	Western Maryland and Eastern West Virginia	409
		6,087

[1] As of December 31, 2017

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, MAIT (effective January 31, 2017) and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP). 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 "Outlook - FERC Matters" below, MAIT and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. In March 2017, FERC approved JCP&L's and MAIT's forward-looking formula rates, subject to refund, with effective dates of June 1, 2017, and July 1, 2017, respectively. Additionally, MAIT and JCP&L filed settlement agreements with FERC on October 13, 2017 and December 21, 2017, respectively, both pending final orders by FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under forward-looking rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which are subject to an annual true-up based on actual costs. 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, Maryland, Michigan, New Jersey and Illinois, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. As of January 31, 2018, this business segment controlled 12,303

MWs of electric generating capacity, including, as further discussed below, 756 MWs of generating capacity which remain subject to an asset purchase agreement with a subsidiary of LS Power that is expected to close in the first half of 2018. 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.

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, 2017, Corporate/Other had $6.8 billion of stand-alone holding company long-term debt, of which $1.45 billion was subject to variable-interest rates, and $300 million was borrowed by FE under its revolving credit facility. On January 22, 2018, FE repaid its $1.45 billion of outstanding variable-interest rate debt using the proceeds from the $2.5 billion equity investment.

EXECUTIVE SUMMARY

FirstEnergy's strategy is to be a fully regulated utility company, focusing on stable and predictable earnings and cash flow from its regulated business units - Regulated Distribution and Regulated Transmission - which focus on delivering enhanced customer service and reliability. Together, the Regulated Distribution and Transmission businesses are expected to provide stable, predictable earnings and cash flows that support FE's dividend.

The scale and diversity of the ten Utilities that comprise the Regulated Distribution business uniquely position this business for growth, through opportunities for additional investment. Since 2015, Regulated Distribution has experienced significant growth through investments that have improved reliability and added operating flexibility to the distribution infrastructure and the implementation of new rates at eight of the ten Utilities in 2017, which provide benefits to the customers and communities those Utilities serve. Based on its current capital plan, which includes $5.7 to $6.7 billion in forecasted capital investments through 2021, Regulated Distribution's rate base growth rate is expected to be approximately 5% through 2021. Additionally, this business is exploring other opportunities for growth, including investments in electric system improvement and modernization projects to increase reliability and improve service to customers, as well as exploring opportunities in customer engagement that focus on the electrification of customers' homes and businesses by providing a full range of products and services.

With approximately 24,500 miles in operations, the Regulated Transmission business is the centerpiece of FirstEnergy's regulated investment strategy with approximately 80% of its capital investments recovered under forward-looking formula rates, including ATSI, TrAIL, and MAIT, which recently filed a proposed settlement with FERC regarding its formula rate, as well as the transmission system at JCP&L, which recently filed a proposed settlement with FERC to maintain a stated-rate through 2020. Both the MAIT and JCP&L settlement agreements are pending before FERC. Regulated Transmission has also experienced significant growth as part of its Energizing the Future transmission plan with $4.4 billion in capital investment from 2014 through 2017 and plans to invest $4.0 to $4.8 billion in capital from 2018 to 2021, which are expected to result in Regulated Transmission rate base growth of approximately 11% through 2021.

FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of approximately $20 billion beyond those identified through 2021, which are expected to strengthen grid and cyber-security and make the transmission system more reliable, robust, secure and resistant to extreme weather events, with improved operational flexibility.

The Company continues to focus on its regulated growth strategy and in November 2016, FirstEnergy announced a strategic review to exit its commodity-exposed generation at CES, which is primarily comprised of the operations of FES and AE Supply. In connection with this strategic review, AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments and through multiple, independent closings. On December 13, 2017, AE Supply completed the sale of the natural gas generating plants with net proceeds, subject to post-closing adjustments, of approximately $388 million. The sale of AE Supply's interests in the Bath County hydroelectric power station and the Buchanan Generating facility is expected to generate net proceeds of $375 million and is anticipated to close in the first half of 2018, subject in each case to various customary and other closing conditions, including, without limitation, receipt of regulatory approvals.

Additionally, on March 6, 2017, AE Supply and MP entered into an asset purchase agreement for MP to acquire AE Supply's Pleasants Power Station (1,300 MWs) for approximately $195 million, resulting from an RFP issued by MP to address its generation shortfall. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC’s affiliate cross-subsidization analysis. On January 26, 2018, the WVPSC approved the transfer of the Pleasants Power Station, subject to certain conditions as further described in "Outlook - West Virginia," below, which included MP assuming significant commodity risk. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement and on February 16, 2018, AE Supply announced its intent to exit operations of the Pleasants Power Station by January 1, 2019, through either sale or deactivation, which resulted in a pre-tax impairment charge of $120 million.

With the sale of the gas plants completed, upon the consummation of the sale of AGC's interest in the Bath County hydroelectric power station or the sale or deactivation of the Pleasants Power Station, AE Supply is obligated under the amended and restated purchase agreement and AE Supply’s applicable debt agreements, to satisfy and discharge approximately $305 million of currently outstanding senior notes as well as its $142 million of pollution control notes and AGC’s $100 million senior notes, which are expected to require the payment of “make-whole” premiums currently estimated to be approximately $95 million based on current interest rates. For additional information see "Outlook" below.

The strategic options to exit the remaining portion of the CES portfolio, which is primarily at FES, are limited. The credit quality of FES, including its unsecured debt rating of Ca at Moody’s, C at S&P, and C at Fitch and the negative outlook from Moody’s and S&P, has challenged its ability to consummate asset sales. Furthermore, the inability to obtain legislative support under the Department of Energy’s recent NOPR, which was rejected by FERC, limits FES’ strategic options to plant deactivations, restructuring its debt and other financial obligations with its creditors, and/or to seek protection under U.S. bankruptcy laws.

As part of the strategic review, FES evaluated its options with respect to its nuclear power plants. Factors considered as part of this review included current and forecasted market conditions, such as wholesale power and capacity prices, legislative and regulatory solutions that recognize their environmental and energy security benefits, and many other factors, including the significant capital and operating costs associated with operating a safe and reliable nuclear fleet. Based on this analysis, given the weak power and capacity price environment and the lack of legislative and regulatory solutions achieved to date, FES concluded that it would be increasingly difficult to operate these facilities in this environment and absent significant change concluded that it was probable that the facilities would be either deactivated or sold before the end of their estimated useful lives. As a result, FES recorded a pre-tax charge of $2.0 billion in the fourth quarter of 2017 to fully impair the nuclear facilities, including the generating plants and nuclear fuel as well as to reserve against the value of materials and supplies inventory and to increase its asset retirement obligation. For additional information see Note 2, "Asset Sales and Impairments."

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of January 31, 2018, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. As previously disclosed, FES has $515 million of maturing debt in 2018 (excluding intra-company debt), beginning with a $100 million principal payment due April 2, 2018. Based on FES' current senior unsecured debt rating, capital structure and long-term cash flow projections, the debt maturities are unlikely to be refinanced. Although management continues to explore cost reductions and other options to improve cash flow, these 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.

On January 22, 2018, FirstEnergy announced a $2.5 billion equity issuance, which included $1.62 billion in mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The preferred shares will receive the same dividend paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The new preferred shares contain an optional conversion for holders beginning in July 2018, and will mandatorily convert in 18-months from the issuance, subject to limited exceptions. Proceeds from the investment were used to reduce holding company debt by $1.45 billion, fund the company’s pension plan by $750 million, with the remainder used for general corporate purposes. Because of this investment, FirstEnergy does not currently anticipate the need to issue additional equity through at least 2021 outside of its regular stock investment and employee benefit plans.

In connection with the equity investment, FirstEnergy formed a RWG composed of three employees of FirstEnergy and two outside members to advise FirstEnergy management regarding an FES restructuring in the event the FES Board decides to seek bankruptcy protection.

On December 22, 2017, the President signed into law the Tax Act. Substantially all of the provisions of the Tax Act are effective for taxable years beginning after December 31, 2017. The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and includes specific provisions related to regulated public utilities including FirstEnergy’s regulated distribution and transmission subsidiaries. The more significant changes that impact FirstEnergy included in the Tax Act are the following:

- Reduction of the corporate federal income tax rate from 35% to 21%, effective in 2018;
- Full expensing of qualified property, excluding rate regulated utilities, through 2022 with a phase down beginning in 2023;
- Limitations on interest deductions with an exception for rate regulated utilities;
- Limitation of the utilization of federal NOLs arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward;

- Repeal of the corporate AMT and allowing taxpayers to claim a refund on any AMT credit carryovers.

As a result of the Tax Act, FirstEnergy recognized a non-cash charge to income tax expense of $1.2 billion ($1.1 billion at FES) and resulted in excess deferred taxes at Regulated Distribution and Regulated Transmission of $2.3 billion, of which the revenue impact was recorded to a regulatory liability. Although certain state utility commissions have initiated proceedings to understand the impact of the Tax Act, the full amount and timing of any refund of excess deferred taxes or the impact of the lower federal income tax rate on future customer utility rates cannot be determined at this time. For additional information see Note 6, "Taxes."

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Years Ended December 31 2017	2016	2015	Increase (Decrease) 2017 vs 2016		2016 vs 2015	
REVENUES:	$14,017	$14,562	$15,026	$(545)	(4)%	$(464)	(3)%
OPERATING EXPENSES:							
Fuel	1,383	1,666	1,855	(283)	(17)%	(189)	(10)%
Purchased power	3,194	3,843	4,423	(649)	(17)%	(580)	(13)%
Other operating expenses	4,232	3,851	3,740	381	10%	111	3%
Pension and OPEB mark-to-market adjustment	141	147	242	(6)	(4)%	(95)	(39)%
Provision for depreciation	1,138	1,313	1,282	(175)	(13)%	31	2%
Amortization of regulatory assets, net	308	297	172	11	4%	125	73%
General taxes	1,043	1,042	978	1	—%	64	7%
Impairment of assets and related charges	2,406	10,665	42	(8,259)	(77)%	10,623	NM
Total operating expenses	13,845	22,824	12,734	(8,979)	(39)%	10,090	79%
OPERATING INCOME (LOSS)	172	(8,262)	2,292	8,434	NM	(10,554)	NM
OTHER INCOME (EXPENSE):							
Investment income (loss)	98	84	(22)	14	17%	106	NM
Impairment of equity method investment	—	—	(362)	—	—%	362	(100)%
Interest expense	(1,178)	(1,157)	(1,132)	(21)	2%	(25)	2%
Capitalized financing costs	79	103	117	(24)	(23)%	(14)	(12)%
Total other expense	(1,001)	(970)	(1,399)	(31)	3%	429	(31)%
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(829)	(9,232)	893	8,403	91%	(10,125)	NM
INCOME TAXES (BENEFITS)	895	(3,055)	315	3,950	NM	(3,370)	NM
NET INCOME (LOSS)	$(1,724)	$(6,177)	$578	$4,453	72%	$(6,755)	NM
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:							
Basic	$(3.88)	$(14.49)	$1.37	$10.61	73%	$(15.86)	NM
Diluted	$(3.88)	$(14.49)	$1.37	$10.61	73%	$(15.86)	NM

NM - Not Meaningful

FirstEnergy’s net loss in 2017 was $(1,724) million, or a basic and diluted loss of $(3.88) per share of common stock, compared with a net loss of $(6,177) million, or a basic and diluted loss of $(14.49) per share of common stock in 2016, and net income of $578 million, or basic and diluted earnings of $1.37 per share of common stock in 2015. Highlights of the key changes in year-over-year financial results are included below:

2017 compared with 2016

FirstEnergy's operating results in 2017 increased $4,453 million as compared to 2016, primarily reflecting lower pre-tax impairment charges of $8,259 million, as follows:

Pre-tax impairment charges of $10,665 million recognized in 2016, include the following:
- Impairment charges of $9,218 million resulting from management's plans to exit its commodity-exposed generation at CES and the anticipated cash flows over the shortened period.
- The impairment of $800 million of goodwill at CES, reflecting a weak outlook for energy and capacity markets.
- Impairment charges totaling $647 million 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.

Pre-tax impairment charges of $2,406 million recognized in 2017, include the following:
- Charges of $2,045 million associated with FES' nuclear generating assets, as discussed above in "Executive Summary."
- Impairment charges of $193 million as a result of the amended asset purchase agreement between AE Supply, AGC, BU Energy and a subsidiary of LS Power.
- Impairment charge of $120 million resulting from AE Supply's announced intent to exit operations of the Pleasants Power Station, through either sale or deactivation by January 1, 2019.
- Impairment charges totaling $41 million associated with formula-rate settlement agreements filed with FERC by MAIT and JCP&L.

Additionally, as a result of the remeasurement of accumulated deferred income taxes in conjunction with the Tax Act, FirstEnergy recognized a non-cash charge to income tax expense of $1,193 million, of which approximately $1,062 million was recognized at CES.

FirstEnergy’s 2017 revenues decreased $545 million as compared to the same period in 2016, resulting from a $1,020 million decrease at CES, partially offset by a $181 million increase at Regulated Transmission and a $105 million increase at Regulated Distribution.

- The decrease in revenues at CES resulted from a 10 million MWH decline in contract sales at lower prices, as well as lower capacity auction prices and lower net gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions.
- The increase in revenues at Regulated Transmission resulted primarily from recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL.
- The increase in revenues at Regulated Distribution resulted from the implementation of new rates in January 2017, partially offset by lower weather-related distribution deliveries and higher customer shopping.

Operating expenses decreased $8,979 million in 2017 as compared to 2016, reflecting a decrease at CES of $8,931 million, primarily associated with the asset impairment charges discussed above, and a decrease at Regulated Distribution of $307 million, partially offset by an increase of $155 million at Regulated Transmission.

- Purchased power decreased $649 million mainly due to lower volumes at CES and Regulated Distribution as well as lower capacity expense at CES.
- Fuel expense decreased $283 million, mainly due to 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.
- Depreciation expense decreased $175 million, mainly from a lower asset base at CES resulting from asset impairments recognized in 2016.
- Other operating expenses increased $381 million, reflecting an increase of $251 million at CES, primarily associated with estimated losses on long-term coal and coal transportation contract disputes recognized in 2017 and higher non-cash mark-to-market losses on commodity contract positions. Operating expenses at Regulated Distribution increased $88 million, resulting primarily from higher operating and maintenance expenses, including increased expenses in Pennsylvania recovered through the new base distribution rates, effective January 27, 2017, and increased storm restoration costs.

Other expense increased $31 million, primarily from higher interest expense and lower capitalized financing costs.

Absent the impact from the Tax Act, discussed above, FirstEnergy’s effective tax rate on pre-tax losses for 2017 and 2016 was 35.9% and 33.1%, respectively. The change in the effective tax rate resulted primarily from the absence of 2016 charges, including $246 million of valuation allowances recorded against state and local 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 was non-deductible for tax purposes.

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 above.

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 increases of $47 million and $98 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 aligned 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 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.
- The increase in revenue at Regulated Transmission primarily resulted from the 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 formula rate.

Operating expenses increased $10,090 million in 2016 as compared to 2015, reflecting an increase at CES of $9,799 million, primarily associated with the asset impairment charges discussed above, and an increase at Regulated Transmission of $78 million, partially offset by a decrease of $50 million at Regulated Distribution.

Changes in certain operating expenses include the following:

- Purchased power decreased $580 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 $111 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, 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, in 2016 $246 million of valuation allowances were recorded against deferred tax assets, that management believes, more likely than not, will not be realized.

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.

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

	2017	2016	2015	Increase (Decrease) 2017 vs 2016	2016 vs 2015
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$916	$651	$588	$265	$63
Regulated Transmission	336	331	328	5	3
Competitive Energy Services	(2,641)	(6,919)	89	4,278	(7,008)
Corporate/Other	(335)	(240)	(427)	(95)	187
Net Income (Loss)	$(1,724)	$(6,177)	$578	$4,453	$(6,755)
Basic Earnings (Loss) Per Share	$(3.88)	$(14.49)	$1.37	$10.61	$(15.86)
Diluted Earnings (Loss) Per Share	$(3.88)	$(14.49)	$1.37	$10.61	$(15.86)

Summary of Results of Operations — 2017 Compared with 2016

Financial results for FirstEnergy's business segments in 2017 and 2016 were as follows:

2017 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,559	$ 1,325	$ 3,063	$ (170)	$ 13,777
Other	175	—	80	(15)	240
Internal	—	—	386	(386)	—
Total Revenues	9,734	1,325	3,529	(571)	14,017
Operating Expenses:					
Fuel	493	—	890	—	1,383
Purchased power	2,924	—	656	(386)	3,194
Other operating expenses	2,517	203	1,777	(265)	4,232
Pension and OPEB mark-to-market adjustment	102	—	39	—	141
Provision for depreciation	724	224	118	72	1,138
Amortization of regulatory assets, net	292	16	—	—	308
General taxes	727	173	99	44	1,043
Impairment of assets and related charges	—	41	2,365	—	2,406
Total Operating Expenses	7,779	657	5,944	(535)	13,845
Operating Income (Loss)	1,955	668	(2,415)	(36)	172
Other Income (Expense):					
Investment income (loss)	54	—	81	(37)	98
Interest expense	(535)	(156)	(179)	(308)	(1,178)
Capitalized financing costs	22	29	27	1	79
Total Other Expense	(459)	(127)	(71)	(344)	(1,001)
Income (Loss) Before Income Taxes (Benefits)	1,496	541	(2,486)	(380)	(829)
Income taxes (benefits)	580	205	155	(45)	895
Net Income (Loss)	$916	$ 336	$ (2,641)	$ (335)	$ (1,724)

2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$9,401	$ 1,144	$ 3,892	$ (174)	$ 14,263
Other	228	—	178	(107)	299
Internal	—	—	479	(479)	—
Total Revenues	9,629	1,144	4,549	(760)	14,562
Operating Expenses:					
Fuel	567	—	1,099	—	1,666
Purchased power	3,303	—	1,019	(479)	3,843
Other operating expenses	2,429	154	1,526	(258)	3,851
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	290	7	—	—	297
General taxes	720	153	134	35	1,042
Impairment of assets and related charges	—	—	10,665	—	10,665
Total Operating Expenses	8,086	502	14,875	(639)	22,824
Operating Income (Loss)	1,543	642	(10,326)	(121)	(8,262)
Other Income (Expense):					
Investment income (loss)	49	—	66	(31)	84
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)

Changes Between 2017 and 2016 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$158	$ 181	$ (829)	$ 4	$ (486)
Other	(53)	—	(98)	92	(59)
Internal	—	—	(93)	93	—
Total Revenues	105	181	(1,020)	189	(545)
Operating Expenses:					
Fuel	(74)	—	(209)	—	(283)
Purchased power	(379)	—	(363)	93	(649)
Other operating expenses	88	49	251	(7)	381
Pension and OPEB mark-to-market adjustment	1	(1)	(6)	—	(6)
Provision for depreciation	48	37	(269)	9	(175)
Amortization of regulatory assets, net	2	9	—	—	11
General taxes	7	20	(35)	9	1
Impairment of assets and related charges	—	41	(8,300)	—	(8,259)
Total Operating Expenses	(307)	155	(8,931)	104	(8,979)
Operating Income	412	26	7,911	85	8,434
Other Income (Expense):					
Investment income (loss)	5	—	15	(6)	14
Interest expense	51	2	15	(89)	(21)
Capitalized financing costs	2	(5)	(10)	(11)	(24)
Total Other Income (Expense)	58	(3)	20	(106)	(31)
Income (Loss) Before Income Taxes (Benefits)	470	23	7,931	(21)	8,403
Income taxes (benefits)	205	18	3,653	74	3,950
Net Income (Loss)	$265	$ 5	$ 4,278	$ (95)	$ 4,453

Regulated Distribution — 2017 Compared with 2016

Regulated Distribution's operating results increased $265 million in 2017, as compared to 2016, primarily reflecting the implementation of approved rates in Ohio, Pennsylvania and New Jersey, and the absence of a $51 million regulatory charge recognized in 2016 resulting from the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV, partially offset by a $30 million non-cash charge to Income tax expense as a result of the Tax Act and lower weather-related customer usage, as further described below.

Revenues —

The $105 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2017	2016	Increase (Decrease)
	(In millions)		
Distribution services	$5,323	$4,721	$ 602
Generation sales:			
Retail	3,767	4,183	(416)
Wholesale	469	497	(28)
Total generation sales	4,236	4,680	(444)
Other	175	228	(53)
Total Revenues	$9,734	$9,629	$ 105

Distribution services revenues increased $602 million primarily resulting from the implementation of the DMR in Ohio, effective January 1, 2017, approved base distribution rate increases in Pennsylvania and New Jersey, effective January 27, 2017, and January 1, 2017, respectively, and higher revenue from the DCR in Ohio. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs and the implementation of certain energy efficiency programs in Ohio. Partially offsetting these rate increases was a decline in MWH deliveries, primarily resulting from lower 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 2017	2016	Increase (Decrease)
	(In thousands)		
Residential	52,048	54,840	(5.1)%
Commercial	41,789	43,340	(3.6)%
Industrial	51,307	50,082	2.4 %
Other	572	579	(1.2)%
Total Electric Distribution MWH Deliveries	145,716	148,841	(2.1)%

Lower distribution deliveries to residential and commercial customers primarily reflect lower weather-related usage resulting from heating degree days that were 4% below 2016, and 11% below normal as well as cooling degree days that were 19% below 2016, but 8% above normal. Deliveries to industrial customers increased reflecting higher shale and steel customer usage.

The following table summarizes the price and volume factors contributing to the $444 million decrease in generation revenues in 2017, as compared to 2016:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$ (250)
Change in prices	(166)
	(416)
Wholesale:	
Effect of increase in sales volumes	15
Change in prices	(30)
Capacity revenue	(13)
	(28)
Decrease in Generation Revenues	$ (444)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania and New Jersey, as well as lower weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 86% from 83% for the Ohio Companies, to 68% from 67% for the Pennsylvania Companies and to 52% from 51% for JCP&L. The decrease in retail generation prices primarily resulted from lower default service auction prices in Ohio, Pennsylvania and New Jersey.

Wholesale generation revenues decreased $28 million in 2017, as compared to 2016, primarily due to lower spot market energy prices and capacity revenue, partially offset by higher wholesale sales. The difference between current wholesale generation revenues and certain energy costs is deferred for future recovery or refund, with no material impact to earnings.

Other revenues decreased $53 million, primarily related to the absence of a $29 million gain on the sale of oil and gas rights at WP recognized in 2016 as well as $20 million in lower transition cost recovery revenues in New Jersey.

Operating Expenses —

Total operating expenses decreased $307 million primarily due to the following:

- Fuel expense decreased $74 million in 2017, as compared to 2016, primarily related to lower unit costs.

- Purchased power costs decreased $379 million in 2017, as compared to 2016, primarily due to decreased volumes, as described above, as well as lower default service auction prices.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (147)
Change due to decreased volumes	(151)
	(298)
Purchases from affiliates:	

Change due to decreased unit costs	(26)
Change due to decreased volumes	(67)
	(93)
Capacity expense	12
Decrease in Purchased Power Costs	$ (379)

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- Other operating expenses increased $88 million primarily due to:
  - Higher network transmission expenses of $35 million. 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 expenses of $64 million, including increased expenses in Pennsylvania recovered through the new base distribution rates, effective January 27, 2017, and increased storm restoration costs, which were deferred for future recovery, resulting in no material impact on current period earnings;
  - Higher energy efficiency program expenses of $45 million in Ohio, which were recovered through higher distribution rider revenues; partially offset by,
  - Lower regulatory costs of $51 million resulting from the absence of economic development and energy efficiency obligations recognized in 2016 in accordance with the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.

- Depreciation expenses increased $48 million due to a higher asset base as well as increased rates in Pennsylvania.

Other Expense —

Total other expense decreased $58 million in 2017, as compared to 2016, primarily related to lower interest expense resulting from various debt maturities at JCP&L, CEI and OE.

Income Taxes —

Regulated Distribution's effective tax rate was 38.8% and 36.5% for 2017 and 2016, respectively. The increase primarily resulted from a $30 million charge to Income tax expense as a result of the remeasurement of accumulated deferred income taxes in conjunction with the Tax Act.

Regulated Transmission — 2017 Compared with 2016

Regulated Transmission's operating results increased $5 million in 2017, as compared to 2016, primarily resulting from the impact of a higher rate base at ATSI and TrAIL partially offset by a pre-tax impairment charge of $41 million, as discussed below.

Revenues —

Total revenues increased $181 million in 2017, as compared to 2016, primarily due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, and the implementation of new rates at MAIT and JCP&L, as further discussed below under "FERC Matters."

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

Revenues by Transmission Asset Owner	For the Years Ended December 31 2017	2016	Increase (Decrease)
	(In millions)		
ATSI	$657	$540	$ 117
TrAIL	282	252	30
MAIT[(1)]	110	101	9
JCP&L	125	91	34
Other	151	160	(9)

Total Revenues	$1,325	$1,144	$ 181

(1) Revenues prior to January 31, 2017, represent transmission revenues under stated rates at ME and PN.

Operating Expenses —

Total operating expenses increased $155 million in 2017, as compared to 2016, principally due to higher operating and maintenance expenses, as well as higher property taxes and depreciation expense due to a higher asset base. Additionally, as a result of settlement agreements filed with FERC regarding the transmission rates for MAIT and JCP&L, a pre-tax impairment charge of $41 million was recognized in 2017. The settlement agreements are currently pending at FERC.

Income Taxes —

Regulated Transmission's effective tax rate was 37.9% and 36.1% for 2017 and 2016, respectively. The increase resulted from a $6 million charge to Income tax expense as a result of the remeasurement of accumulated deferred income taxes in conjunction with the Tax Act.

CES — 2017 Compared with 2016

Operating results increased $4,278 million in 2017, as compared to 2016, primarily due to lower asset impairment and plant exit costs, as discussed in "Financial Overview," above, and lower depreciation expense, partially offset by a charge to Income tax expense of $1,062 million as a result of the Tax Act, pre-tax charges of $318 million associated with estimated losses on long-term coal and coal transportation contract disputes, as discussed in "Outlook - Environmental Matters" below, higher non-cash mark-to-market losses on commodity contract positions, lower capacity revenue, and the impact of lower contract sales.

Revenues —

Total revenues decreased $1,020 million in 2017, as compared to 2016, primarily due to lower capacity auction prices, lower contract sales volumes at lower prices, and lower net gains on financially settled contracts, partially offset by 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 2017	2016	(Decrease)
	(In millions)		
Contract Sales:			
Direct	$735	$812	$ (77)
Governmental Aggregation	396	814	(418)
Mass Market	127	169	(42)
POLR	504	583	(79)
Structured Sales	346	463	(117)
Total Contract Sales	2,108	2,841	(733)
Wholesale	1,300	1,457	(157)
Transmission	41	73	(32)
Other	80	178	(98)
Total Revenues	$3,529	$4,549	$ (1,020)

MWH Sales by Channel	For the Years Ended December 31 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	15,157	15,310	(1.0)%

Governmental Aggregation	7,431	13,730	(45.9)%
Mass Market	1,867	2,431	(23.2)%
POLR	9,140	9,969	(8.3)%
Structured Sales	8,972	11,414	(21.4)%
Total Contract Sales	42,567	52,854	(19.5)%
Wholesale	22,492	15,201	48.0 %
Total MWH Sales	65,059	68,055	(4.4)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(8)	$(69)	$ —	$ —	$(77)
Governmental Aggregation	(373)	(45)	—	—	(418)
Mass Market	(40)	(2)	—	—	(42)
POLR	(49)	(30)	—	—	(79)
Structured Sales	(101)	(16)	—	—	(117)
Wholesale	202	23	(156)	(226)	(157)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract in 2016. The Direct, Governmental Aggregation and Mass Market customer base was approximately 900,000 as of December 31, 2017, compared to 1.1 million as of December 31, 2016. Although unit pricing was lower year-over-year in the Direct, Governmental Aggregation and Mass Market channels, the decrease was primarily attributable to lower capacity rates, as discussed below, which is a component of the retail price.

The decrease in POLR revenue of $79 million was primarily due to both lower volumes and lower unit prices. Structured revenue decreased $117 million, primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues decreased $157 million, primarily due to a decrease in capacity revenue from lower capacity auction prices and lower net gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions at higher market prices.

Transmission revenue decreased $32 million, primarily due to lower congestion revenue associated with less volatile market conditions.

Other revenue decreased $98 million, primarily due to lower lease revenues from the expiration of a nuclear sale-leaseback agreement. CES earned lease revenue associated with the lessor equity interests it had purchased in sale-leaseback transactions, one of which expired in June 2017 and another in May 2016.

Operating Expenses —

Total operating expenses decreased $8,931 million in 2017 due to the following:

- Fuel costs decreased $209 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts recognized in 2016, as well as lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as discussed above, partially offset by higher unit costs.

- Purchased power costs decreased $363 million primarily due to lower capacity expenses ($271 million) and lower unit costs ($126 million), partially offset by higher volumes ($34 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 unit costs primarily resulted from lower wholesale spot market prices, as discussed above.

- Charges of $318 million associated with estimated losses on long-term coal and coal transportation contract disputes was recognized in 2017, as discussed in "Outlook - Environmental Matters" below.
- Fossil operating and maintenance expenses decreased $18 million, primarily due to lower outage costs.
- Nuclear operating and maintenance expenses increased $14 million, primarily as a result of higher employee benefit costs, partially offset by lower refueling outage costs.
- Retirement benefit costs decreased $14 million.
- Transmission expenses decreased $60 million, primarily due to lower contract sales volumes.

- Other operating expenses increased $11 million, primarily due to higher non-cash mark-to-market losses on commodity contract positions, partially offset by the absence of a termination charge recognized in 2016 associated with an FES Governmental Aggregation customer contract and lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement.
- Depreciation expense decreased $269 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016, partially offset by the absence of an out-of-period adjustment to reduce the depreciation of a hydroelectric generating station in the third quarter of 2016.
- General taxes decreased $35 million, primarily due to lower property taxes and reduced gross receipts taxes associated with lower retail sales volumes.
- Impairment of assets and related charges decreased $8,300 million, primarily due to the absence of impairments recognized in 2016 related to goodwill and the competitive generation assets primarily resulting from the strategic review announced in November 2016, partially offset by the impairments recognized in 2017 related to the nuclear generating assets and the Pleasants Power Station, as discussed further in "Executive Summary," above.

Other Expense —

Total other expense decreased $20 million in 2017, as compared to 2016, primarily due to lower OTTI on NDT investments and lower net financing costs resulting from PCRB repurchases by FG and NG in 2017 and 2016.

Income Taxes (Benefits) —

Absent the impact from the Tax Act, discussed above, CES' effective tax rate on pre-tax losses for 2017 and 2016 was 36.5% and 33.6%, respectively. The change in the effective tax rate year-over-year resulted primarily from the absence of 2016 charges, including $246 million of valuation allowances recorded against state and local deferred tax assets, that management believes, more likely than not, will not be realized, as well as the impairment of $800 million of goodwill recognized in 2016, of which $433 million was non-deductible for tax purposes.

Corporate/Other — 2017 Compared with 2016

Financial results from the Corporate/Other operating segment and reconciling adjustments resulted in a $95 million decrease in consolidated earnings in 2017, as compared to 2016, primarily associated with higher interest expense and a charge to Income tax expense as a result of the remeasurement of accumulated deferred income taxes in conjunction with the Tax Act. Higher interest expense resulted from the issuance of $3 billion of senior notes in June 2017.

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	$ 1,144	$ 3,892	$ (174)	$ 14,263
Other	228	—	178	(107)	299
Internal	—	—	479	(479)	—
Total Revenues	9,629	1,144	4,549	(760)	14,562
Operating Expenses:					
Fuel	567	—	1,099	—	1,666
Purchased power	3,303	—	1,019	(479)	3,843
Other operating expenses	2,429	154	1,526	(258)	3,851
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	290	7	—	—	297
General taxes	720	153	134	35	1,042
Impairment of assets and related charges	—	—	10,665	—	10,665
Total Operating Expenses	8,086	502	14,875	(639)	22,824
Operating Income (Loss)	1,543	642	(10,326)	(121)	(8,262)
Other Income (Expense):					
Investment income (loss)	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	$ 1,046	$ 4,493	$ (165)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,582	1,046	5,384	(986)	15,026
Operating Expenses:					
Fuel	533	—	1,322	—	1,855
Purchased power	3,653	—	1,456	(686)	4,423
Other operating expenses	2,231	148	1,670	(309)	3,740
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	165	7	—	—	172
General taxes	703	102	140	33	978
Impairment of assets and related charges	8	—	34	—	42
Total Operating Expenses	8,136	424	5,076	(902)	12,734
Operating Income (Loss)	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 (Loss) Before Income Taxes (Benefits)	913	519	139	(678)	893
Income taxes (benefits)	325	191	50	(251)	315
Net Income (Loss)	$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	$ 98	$ (601)	$ (9)	$ (497)
Other	32	—	(27)	28	33
Internal	—	—	(207)	207	—
Total Revenues	47	98	(835)	226	(464)
Operating Expenses:					
Fuel	34	—	(223)	—	(189)
Purchased power	(350)	—	(437)	207	(580)
Other operating expenses	198	6	(144)	51	111
Pension and OPEB mark-to-market adjustment	(78)	(2)	(15)	—	(95)
Provision for depreciation	12	23	(7)	3	31
Amortization of regulatory assets, net	125	—	—	—	125
General taxes	17	51	(6)	2	64
Impairment of assets and related charges	(8)	—	10,631	—	10,623
Total Operating Expenses	(50)	78	9,799	263	10,090
Operating Income (Loss)	97	20	(10,634)	(37)	(10,554)
Other Income (Expense):					
Investment income (loss)	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 operating results increased $63 million in 2016, as 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	$4,721	$4,459	$ 262
Generation sales:			
Retail	4,183	4,354	(171)
Wholesale	497	573	(76)
Total generation sales	4,680	4,927	(247)
Other	228	196	32
Total Revenues	$9,629	$9,582	$ 47

Distribution services revenues increased $262 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 $247 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	25
	(171)
Wholesale:	
Effect of increase in sales volumes	47
Change in prices	(107)
Capacity revenue	(16)
	(76)
Decrease in Generation Revenues	$ (247)

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 as compared to 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 2015, primarily related to higher generation.

- Purchased power costs decreased $350 million, in 2016 as compared to 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	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)
Decrease in Purchased Power Costs	$ (350)

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- Other operating expenses increased $198 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 $125 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)
  - The recovery of previously deferred energy and fuel costs ($75 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

Regulated Transmission's operating results increased $3 million, in 2016 as 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 $98 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
	(In millions)		
ATSI	$540	$446	$ 94
TrAIL	252	252	—
MAIT[1]	101	100	1
JCPL	91	89	2
Other	160	159	1
Total Revenues	$1,144	$1,046	$ 98

[1] Revenues represent transmission revenues under stated rates at ME and PN.

Operating Expenses —

Total operating expenses increased $78 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 as 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 FES' strategy to more effectively hedge its generation. 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.

- 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.
- 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 $39 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.
- Impairment of assets and related charges increased $10,631 million, primarily due to impairments of goodwill and the competitive generation assets further 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 $246 million of valuation allowances recorded against 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 was 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.

Regulatory Assets and Liabilities

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.

As a result of the Tax Act, FirstEnergy adjusted its net deferred tax liabilities at December 31, 2017, for the reduction in the corporate income tax rate from 35% to 21%. For the portions of FirstEnergy's business that apply regulatory accounting, the impact of reducing the net deferred tax liabilities was offset with a regulatory liability, as appropriate, for amounts expected to be refunded to rate payers in future rates, with the remainder recorded to deferred income tax expense.

The following table provides information about the composition of net regulatory assets and liabilities as of December 31, 2017 and December 31, 2016, and the changes during the year ended December 31, 2017:

Net Regulatory Assets (Liabilities) by Source	December 31, 2017	December 31, 2016	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$46	$ 90	$ (44)
Customer receivables (payables) for future income taxes	(2,765)	468	(3,233)
Nuclear decommissioning and spent fuel disposal costs	(323)	(304)	(19)
Asset removal costs	(774)	(770)	(4)
Deferred transmission costs	187	122	65
Deferred generation costs	198	331	(133)
Deferred distribution costs	258	296	(38)
Contract valuations	118	153	(35)
Storm-related costs	329	397	(68)
Other	46	74	(28)
Net Regulatory Assets (Liabilities) included on the Consolidated Balance Sheets	$(2,680)	$ 857	$ (3,537)

Regulatory assets that do not earn a current return totaled approximately $7 million and $153 million as of December 31, 2017 and 2016, respectively, primarily related to storm damage costs, and are currently being recovered through rates.

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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.

On January 22, 2018, FirstEnergy announced a $2.5 billion equity issuance, which included $1.62 billion in mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The preferred shares will receive the same dividend paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The new preferred shares contain an optional conversion for holders beginning in July 2018, and will mandatorily convert in 18-months from the issuance, subject to limited exceptions. Proceeds from the investment were used to reduce holding company debt by $1.45 billion and fund the company’s pension plan by $750 million, with the remainder used for general corporate purposes.

The equity investment allows FirstEnergy to strengthen its balance sheet and supports the company's transition to a fully regulated utility company. By deleveraging the company, the investment will also enable FirstEnergy to enhance its investment grade credit metrics and FirstEnergy does not currently anticipate the need to issue additional equity through at least 2021 outside of its regular stock investment and employee benefit plans.

In addition to this equity investment, 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 2018 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 may be met through the issuance of long-term debt at certain utility and transmission subsidiaries to, among other things, fund capital expenditures and 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, an unregulated companies' money pool (which also includes FE, FET, FEV and certain other unregulated subsidiaries of FE but excludes FENOC, FES and its subsidiaries) and proceeds generated from previously disclosed asset sales, subject to closing, and in the case of FES, its current access to a separate unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, and a two-year secured line of credit from FE of up to $500 million, as further described below.

FES subsidiaries have debt maturities of $515 million in 2018, (excluding intra-company debt), beginning with a $100 million principal payment due April 2, 2018. Based on FES' current senior unsecured debt rating, capital structure and long-term cash flow projections, the debt maturities are unlikely to be refinanced. Although management continues to explore cost reductions and other options to improve cash flow, these 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. Furthermore, the inability to obtain legislative support under the Department of Energy’s recent NOPR, which was rejected by FERC, limits FES’ strategic options to plant deactivations, restructuring its debt and other financial obligations with its creditors, and/or to seek protection under U.S. bankruptcy laws.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed 2017 funding obligations 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 January 2018, FirstEnergy satisfied its minimum required funding obligations of $500 million and, as discussed above, addressed funding obligations for future years to its qualified pension plan with additional contributions of $750 million.

FirstEnergy's capital expenditures for 2018 are expected to be approximately $2.6 billion to $2.9 billion, excluding CES. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

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

Reportable Segment	2017 Actual[1]	2017 Pension/OPEB Mark-to-Market Capital Adjustment	2017 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2018 Forecast[2]
	(In millions)			
Regulated Distribution	$1,342	$ (20)	$ 1,362	$1,500 - $1,600
Regulated Transmission	1,032	1	1,031	1,000 - 1,200
CES	279	(1)	280	— [3]
Corporate/Other	99	—	99	100
Total	$2,752	$ (20)	$ 2,772	$2,600 - $2,900

[1] Includes a decrease of approximately $20 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] Planned capital expenditures will be dependent on the outcome of the strategic review of CES.

Additionally, planned capital expenditures for Regulated Distribution includes $1.4 billion to $1.7 billion, annually, 2019 through 2021, while planned capital expenditures for Regulated Transmission are expected to be approximately $1.0 billion to $1.2 billion, annually, 2019 through 2021.

Capital expenditures for 2017 and 2018 forecast by subsidiary are included in the following table.

Operating Company	2017 Actual[1]	2017 Pension/OPEB Mark-to-Market Capital Adjustment	2017 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2018 Forecast[2][3]
	(In millions)			
OE	$143	$ (12)	$ 155	$ 160
Penn	55	(1)	56	45
CEI	134	4	130	145
TE	37	(3)	40	50
JCP&L	317	3	314	380
ME	142	(4)	146	185
PN	162	(12)	174	195
MP	269	9	260	280
PE	112	—	112	150
WP	199	(2)	201	260
ATSI	541	—	541	375
TrAIL	45	—	45	55
FES	250	(3)	253	— [4]
AE Supply	34	2	32	— [4]
MAIT	242	(1)	243	400
Other subsidiaries	70	—	70	70
Total	$2,752	$ (20)	$ 2,772	$ 2,750

(1) Includes a decrease of approximately $20 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) 2018 Forecast represents the mid-point of Regulated Distribution and Regulated Transmission's 2018 forecasted capital expenditures.
(4) Planned capital expenditures will be dependent on the outcome of the strategic review of CES.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the Energizing the Future transmission plan, pursuant to which FirstEnergy plans to invest $4.0 to $4.8 billion in capital investments from 2018 to 2021, with $4.4 billion in capital investment 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. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,500 mile transmission system, making this a continuing platform for investment in the years beyond 2021.

As of December 31, 2017, FirstEnergy’s and FES' net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt. Currently payable long-term debt as of December 31, 2017, included the following:

Currently Payable Long-Term Debt	FirstEnergy	FES
	(In millions)	
Unsecured notes	$150	$—
FMBs	325	—
Secured PCRBs	141	141
Unsecured PCRBs	374	374
Sinking fund requirements	61	—
Other notes	31	9
	$1,082	$524

Short-Term Borrowings / Revolving Credit Facilities

FE and the Utilities and FET and its subsidiaries participate in two separate five-year syndicated revolving credit facilities with aggregate commitments of $5.0 billion (Facilities), which are available through December 6, 2021. FE and the Utilities and FET and its subsidiaries may use borrowings under their Facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt-to-total-capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

FirstEnergy had $300 million and $2,675 million of short-term borrowings as of December 31, 2017 and 2016, respectively. FirstEnergy’s available liquidity from external sources as of January 31, 2018 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy(1)	Revolving	December 2021	$4,000	$ 3,740
FET(2)	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 4,740
		Cash	—	358
		Total	$5,000	$ 5,098

(1) FE and the Utilities. Available liquidity includes impact of $10 million of LOCs issued under various terms.
(2) Includes FET, ATSI, MAIT and TrAIL.

FES had $105 million and $101 million of short-term borrowings as of December 31, 2017 and December 31, 2016, respectively. Of such amounts, $102 million and $101 million, respectively, represents a currently outstanding promissory note due April 2, 2018, payable to AE Supply with any additional short-term borrowings representing borrowings under an unregulated companies' money pool, which also includes FE, FET, FEV and certain other unregulated subsidiaries of FE, but excludes FENOC, FES and its subsidiaries. In addition to FES' access to a separate unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, FES' available liquidity as of January 31, 2018, was as follows:

Type	Commitment	Available Liquidity
	(In millions)	
Two-year secured credit facility with FE	$ 500	$ 500
Cash	—	1
	$ 500	$ 501

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 January 31, 2018:

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	300	—	300	(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)

(1) No limitations.
(2) Includes amounts which may be borrowed under the regulated companies' money pool.

$250 million of the FE Facility and $100 million of the FET Facility, subject to each borrower’s sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower’s borrowing sub-limit.

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

As of December 31, 2017, the borrowers were in compliance with the applicable debt-to-total-capitalization covenants, as well as in the case of FE, the minimum interest coverage ratio requirement, in each case as defined under the respective Facilities.

Separately, in December 2016, FE and FES entered into a two-year secured credit facility in which FE provides a committed line of credit to FES of up to $500 million and additional credit support of up to $200 million to cover surety bonds for $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's

Ferry disposal site, respectively. So long as FES remains in an unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, the $500 million secured line of credit provides FES the needed liquidity in order for FES to, among other things, satisfy its nuclear support obligation to NG in the event of extraordinary circumstances with respect to its nuclear facilities. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million). Additionally, FES maintains access to an unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, and continues to conduct its ordinary course of business under that money pool in lieu of borrowing under the new facility.

Term Loans

As of December 31, 2017, FE had a $1.2 billion variable rate syndicated term loan and two separate $125 million term loans. On January 22, 2018, FE repaid these term loans in full using the proceeds from the $2.5 billion equity investment.

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. Similar but separate arrangements exist among FirstEnergy’s unregulated companies with AE Supply, FE, FET, FEV and certain other unregulated subsidiaries of FE participating in a money pool and FE (as a lender only), FENOC, FES and its subsidiaries participating in a similar money pool. FESC administers these money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as the case may be, 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 2017 was 1.48% per annum for the regulated companies’ money pool and 2.30% per annum for the unregulated companies’ money pools.

As discussed above, FES currently maintains access to its unregulated companies' money pool in lieu of borrowing under its $500 million secured line of credit. FE expects to provide ongoing liquidity to FES within such unregulated companies' money pool through March 2018. As of December 31, 2017, FES, its subsidiaries, and FENOC had no borrowings in the aggregate under the unregulated companies' money pool.

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, 2018:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FE	—	—	—	BB+	Baa3	BBB-
FES	CCC+	B3	—	C	Ca	C
AE Supply	BB	—	BB	BB-	B1	BB-
AGC	—	—	—	BB-	Baa3	BB
ATSI	—	—	—	BBB-	Baa1	BBB+
CEI	BBB+	Baa1	A-	BBB-	Baa3	BBB+
FET	—	—	—	BB+	Baa2	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	A3	BBB+
MAIT	—	—	—	BBB-	Baa1	BBB
MP	BBB+	A3	BBB+	—	—	—
OE	BBB+	A2	A-	BBB-	Baa1	BBB+
PN	—	—	—	BBB-	Baa1	BBB+
Penn	—	A2	A-	—	—	—
PE	—	—	—	—	—	—
TE	BBB+	Baa1	A-	—	—	—
TrAIL	—	—	—	BBB-	A3	BBB+
WP	BBB+	A1	A-	—	—	—

Debt capacity is subject to the consolidated debt-to-total-capitalization limits in the credit facilities previously discussed. As of January 31, 2018, FE and its subsidiaries could issue additional debt of approximately $6.6 billion, or incur a $3.5 billion reduction to equity, and remain within the limitations of the financial covenants required by the FE Facility.

Changes in Cash Position

As of December 31, 2017, FirstEnergy had $589 million of cash and cash equivalents compared to $199 million of cash and cash equivalents as of December 31, 2016. As of December 31, 2017 and 2016, FirstEnergy had approximately $54 million and $61 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 $3,808 million during 2017, $3,383 million during 2016 and $3,460 million during 2015.

2017 compared with 2016

Cash flows from operations increased $425 million in 2017 as compared with 2016. The year-over-year change in cash from operations increased due to the following:

- the absence of $382 million in cash contributions to the qualified pension plan in 2016;
- higher transmission revenue, reflecting recovery of incremental operating expenses, a higher rate base at ATSI and TrAIL, and the implementation of new rates at MAIT and JCP&L;
- higher distribution services retail receipts reflecting implementation of approved rates in Ohio, Pennsylvania and New Jersey, as further described above; partially offset by
- lower receipts from a decrease in capacity revenue and contract sales at CES.

2016 compared with 2015

Cash flows from operations decreased $77 million in 2016 compared with 2015 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.

Cash Flows From Financing Activities

In 2017, cash used for financing activities was $702 million compared to $34 million in 2016 and $292 million in 2015. The following table summarizes new debt financing, redemptions, repayments, short-term borrowings and dividends:

Securities Issued or Redeemed / Repaid	For the Years Ended December 31 2017	2016	2015
	(In millions)		
New Issues			
Unsecured notes	$3,800	$—	$475
PCRBs	—	471	339
FMBs	625	305	295
Term loan	250	1,200	200
Senior secured notes	—	—	2
	$4,675	$1,976	$1,311
Redemptions / Repayments			
Unsecured notes	$(1,330)	$(300)	$—
PCRBs	(158)	(483)	(313)
FMBs	(725)	(246)	(215)
Term loan	—	(1,200)	(200)
Senior secured notes	(78)	(102)	(151)
	$(2,291)	$(2,331)	$(879)
Short-term borrowings (repayments), net	$(2,375)	$975	$(91)
Common stock dividend payments	$(639)	$(611)	$(607)

On March 1, 2017, FG retired $28 million of PCRBs at maturity.

On March 15, 2017, MP retired $150 million of FMBs at maturity.

On April 3, 2017, CEI retired $130 million of 5.70% senior notes at maturity.

On May 16, 2017, MP issued $250 million of 3.55% FMBs due 2027. Proceeds received from the issuance of the FMBs were used: (i) to repay short-term borrowings, (ii) to fund capital expenditures and (iii) for working capital needs and other general business purposes.

On June 1, 2017, FG repurchased approximately $130 million of PCRBs, which were subject to a mandatory put on such date. FG is currently holding these PCRBs indefinitely.

On June 1, 2017, JCP&L retired $250 million of 5.65% senior notes at maturity.

On June 21, 2017, FE issued the aggregate principal amount of $3.0 billion of its senior notes in three series: $500 million of 2.85% notes due 2022; $1.5 billion of 3.90% notes due 2027; and $1.0 billion of 4.85% notes due 2047. Proceeds from the issuance of the notes were used: (i) to redeem $650 million of FE's 2.75% notes due in 2018 on July 25, 2017, and (ii) for general corporate purposes, including the repayment of short-term borrowings under the FE

Facility.

On August 31, 2017, ATSI issued $150 million of 3.66% senior unsecured notes maturing in 2032. Proceeds from the issuance of the notes were used: (i) to repay short-term borrowings, (ii) to fund capital expenditures and (iii) for working capital needs and other general business purposes.

On September 8, 2017, PN issued $300 million of 3.25% senior notes maturing in 2028. Proceeds from the issuance of the notes were used to repay short-term borrowings that were used to repay at maturity $300 million of PN's 6.05% senior notes due September 1, 2017.

On September 15, 2017, WP issued $100 million of 4.09% FMBs due 2047. Proceeds from the issuance of the FMBs were used: (i) to repay short-term borrowings, (ii) to fund capital expenditures and (iii) for other general business purposes.

On October 5, 2017, CEI issued $350 million of 3.50% senior notes maturing in 2028. Proceeds from the issuance of the notes were used: (i) to refinance existing indebtedness, including $300 million of 7.88% FMBs due November 1, 2017, and borrowings outstanding under FirstEnergy's regulated utility money pool and the Facility, (ii) to fund capital expenditures and (iii) for working capital and other general business purposes.

On December 15, 2017, WP issued $275 million of 4.14% FMBs maturing in 2047. Proceeds from the issuance of the FMBs were used to repay at maturity $275 million of WP's 5.95% FMBs due December 15, 2017.

Cash Flows From Investing Activities

Cash used for investing activities in 2017 principally represented cash used for property additions. The following table summarizes investing activities for 2017, 2016 and 2015:

	For the Years Ended December 31		
Cash Used for Investing Activities	2017	2016	2015
	(In millions)		
Property Additions:			
Regulated Distribution	$1,191	$1,063	$1,040
Regulated Transmission	1,030	1,101	1,020
Competitive Energy Services	317	619	588
Corporate/Other	49	52	56
Nuclear fuel	254	232	190
Proceeds from asset sales	(388)	(15)	(20)
Investments	98	111	114
Asset removal costs	172	145	142
Other	(7)	(27)	(8)
	$2,716	$3,281	$3,122

2017 compared with 2016

Cash used for investing activity in 2017 decreased $565 million, as compared to 2016, primarily due to lower property additions. The decline in property additions was due to the following:

- a decrease of $302 million at CES, resulting from lower capital investments associated with outages, MATS compliance and the Mansfield dewatering facility,
- a decrease of $71 million at Regulated Transmission due to timing of capital investments associated with its Energizing the Future investment program; partially offset by,
- an increase of $128 million at Regulated Distribution due to an increase in storm restoration work and smart meter investments in Pennsylvania.

2016 compared with 2015

Cash used for investing activity in 2016 increased $159 million, as compared to 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.

CONTRACTUAL OBLIGATIONS

As of December 31, 2017, FirstEnergy's estimated cash payments under existing contractual obligations that it considers firm obligations are as follows:

Contractual Obligations	Total	2018	2019-2020	2021-2022	Thereafter
	(In millions)				
Long-term debt[1]	$22,266	$1,051	$ 2,548	$ 3,460	$ 15,207
Short-term borrowings	300	300	—	—	—
Interest on long-term debt[2]	13,972	1,081	1,951	1,773	9,167
Operating leases[3]	1,874	146	230	235	1,263
Capital leases[3]	117	28	41	28	20
Fuel and purchased power[4]	9,110	1,260	1,956	1,395	4,499
Capital expenditures [5]	1,778	558	625	595	—
Pension funding[6]	2,217	1,250	—	460	507
Total	$51,634	$5,674	$ 7,351	$ 7,946	$ 30,663

(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, 2017.
(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, 2017.
(6) In January 2018, FirstEnergy satisfied its minimum required funding obligations of $500 million and addressed funding obligations through 2020 to its qualified pension plan with additional contributions of $750 million. The impact of the contributions is reflected in the table above.

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 $2.8 billion in 2018, of which $300 million 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 $13.4 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $450 million; and (ii) $13.0 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 and NG's maximum potential assessment under these provisions would be $509 million per incident but not more than $76 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 yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.4 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 and its subsidiaries could be required to make under these guarantees as of December 31, 2017, was approximately $3.8 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)]	$ 7
Deferred compensation arrangements[(2)]	592
AE Supply asset sales[(3)]	555
Fuel-Related[(4)]	72
Other[(5)]	4
	1,230
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts[(6)]	265
FES' guarantee of FG's sale and leaseback obligations	1,574
	1,839
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	275
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	128
Surety Bonds[(7),(8)]	263
Sale leaseback indemnity	58
LOCs[(9)]	10
	459
Total Guarantees and Other Assurances	$ 3,803

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

(2) CES related portion is $149 million, including $58 million and $91 million at FES and FENOC, respectively.

(3) As a condition to closing the sale of the natural gas generating plants, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement.

(4) FE is the guarantor of the remaining payments due to CSX/BNSF in connection with the definitive settlement on a transportation agreement.

(5) Includes guarantees of $4 million for various leases.

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

(7) FE provides credit support for FG surety bonds for $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's Ferry disposal site, respectively.

(8) FE provides credit support for $23 million of surety bonds held by AE Supply.

(9) Includes $10 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities.

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 CES' power portfolio exposure as of December 31, 2017, FES has posted collateral of $123 million and AE Supply has posted collateral of $4 million. The Regulated Distribution Segment has posted collateral of $4 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, 2017:

Potential Collateral Obligations	FES	AE Supply	Regulated	FE Corp	Total
	(In millions)				
Contractual Obligations for Additional Collateral					
At Current Credit Rating	$4	$ 1	$ —	$—	$5
Upon Further Downgrade	—	—	41	—	41
Surety Bonds (Collateralized Amount)[1]	16	1	107	237	361
Total Exposure from Contractual Obligations	$20	$ 2	$ 148	$237	$407

[1] Surety Bonds are not tied to a credit rating. Surety Bonds' impact assumes maximum contractual obligations (typical obligations require 30 days to cure). FE provides credit support for FG surety bonds for $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's Ferry disposal site, respectively.

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2017, FES has $2 million of collateral posted with its affiliates.

Other Commitments and Contingencies

FE is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding's outstanding principal balance is $275 million. In addition to FE, 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 has obligations that are not included on its Consolidated Balance Sheet related to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements (expiring in 2040), which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $862 million as of December 31, 2017. As of December 31, 2017, FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

On June 1, 2017, NG completed the purchase of the 2.60% lessor equity interests of the remaining non-affiliated leasehold interests in Beaver Valley Unit 2 for $38 million. In addition, the Beaver Valley Unit 2 leases expired in accordance with their terms on June 1, 2017, resulting in NG being the sole owner of Beaver Valley Unit 2.

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 Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy 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, 2017, are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2018	2019	2020	2021	2022	Thereafter	Total
	(In millions)						
Other external sources[1]	$(25)	$(35)	$(11)	$ —	$ —	$ —	$(71)
Prices based on models	1	—	—	—	—	—	1
Total[2]	$(24)	$(35)	$(11)	$ —	$ —	$ —	$(70)

(1) Primarily represents contracts based on broker and ICE quotes.

(2) Includes $(79) 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 changes in market values 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, 2017, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $6 million during the next twelve months.

Equity Price Risk

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2017, approximately 55% of the funds were invested in fixed income securities, 41% of the funds were invested in equity securities and 4% 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 $1,491 million, $1,104 million and $90 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2017, excluding $(7) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $110 million reduction in fair value as of December 31, 2017. 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 2017, FirstEnergy made no contributions to the NDTs.

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	2018	2019	2020	2021	2022	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$—	$—	$—	$—	$—	$1,738	$1,738	$1,738
Average interest rate	— %	— %	— %	— %	— %	3.3 %	3.3 %	
Liabilities:								
Long-term Debt:								
Fixed rate	$679	$1,035	$541	$490	$1,100	$16,957	$20,802	$21,579
Average interest rate	6.8 %	6.5 %	5.5 %	5.7 %	4.1 %	4.9 %	5.0 %	
Variable rate(1)	$—	$9	$250	$1,200	$—	$—	$1,459	$1,459
Average interest rate	— %	1.1 %	2.4 %	2.4 %	— %	— %	2.4 %	

(1) As of December 31, 2017, FE had a $1.2 billion variable rate syndicated term loan and two separate $125 million term loans. On January 22, 2018, FE repaid these term loans in full using the proceeds from the $2.5 billion equity investment.

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, Maryland, Michigan, New Jersey and Illinois, 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.

Following the adoption of the Tax Act, various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities’ rates and charges. State proceedings which have arisen are discussed below. The Utilities continue to monitor and investigate the impact of state regulatory impacts resulting from the Tax Act.

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. 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 achieved under PE's current plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER Maryland program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. The costs of PE's 2015-2017 plan approved by the MDPSC in December 2014 were approximately $60 million. PE filed its 2018-2020 EmPOWER Maryland plan on August 31, 2017. The 2018-2020 plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. On December 22, 2017, the MDPSC issued an order approving the 2018-2020 plan with various modifications. PE recovers 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 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. Comments were filed and a hearing was held in late 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. On January 19, 2018, PE filed a joint petition, along with other utility companies, work group stakeholders, and the MDPSC electric vehicle work group leader, to implement a statewide electric vehicle portfolio. If approved, PE will launch an electric vehicle charging infrastructure program on January 1, 2019, offering up to 2,000 rebates for electric vehicle charging equipment to residential customers, and deploying up to 259 chargers at non-residential customer service locations at a projected total cost of $12 million. PE is proposing to recover program costs subject to a five-year amortization. On February 6, 2018, the MDPSC opened a new proceeding to consider the petition and directed that comments be filed by March 16, 2018.

On January 12, 2018, the MDPSC instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of Maryland utilities. PE must track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and submitted a report to the MDPSC on February 15, 2018, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers and proposed to file a base rate case in the third quarter of 2018 where the benefits from the effects of the Tax Act will be realized by customers through a lower rate increase than would otherwise be necessary.

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.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended 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. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L’s 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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 included 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, 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 Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On December 19, 2017, the NJBPU approved the issuance of proposed rules to modify the CTA methodology consistent with its October 22, 2014 Generic Order. The proposed rule was published in the NJ Register on January 16, 2018, and was republished on February 6, 2018, to correct an error. Interested parties have sixty days to comment on the proposed rulemaking.

At the December 19, 2017 NJBPU public meeting, the NJBPU approved its IIP rulemaking. The IIP creates a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety. JCP&L expects to make a filing in 2018.

On January 31, 2018, the NJBPU instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of New Jersey utilities. JCP&L must track and apply regulatory accounting treatment for the impacts effective January 1, 2018, and file a petition with the NJBPU by March 2, 2018, regarding the expected impacts of the Tax Act on JCP&L’s expenses and revenues and how the effects will be passed through to its customers.

OHIO

The Ohio Companies currently operate under ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO’s Opinion and Order issued on March 31, 2016 and Fifth Entry on Rehearing on 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. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $204 million annually. Revenues from 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 $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: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016, and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates (which filing was made on April 3, 2017, and remains pending).

Several parties, including the Ohio Companies, filed applications for rehearing regarding 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 August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies' challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO's August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the Ohio Manufacturer's Association Energy Group filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. On November 16, 2017, the Ohio Companies intervened in the appeal. Additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. For additional information, see "FERC Matters - Ohio ESP IV PPA," below.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. 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 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. 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. On November 21, 2017, the PUCO issued an order that approved the filed Stipulation and Recommendation with several modifications, including a cap on the Ohio Companies' collection of program costs and shared savings set at 4% of the Ohio Companies' total sales to customers as reported on FERC Form 1. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO's modification of the Stipulation and Recommendation to include the 4% cost cap, which was denied by the PUCO on January 10, 2018.

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 that in 2014 SB310 froze 2015 and 2016 requirements at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. 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. The OCC and the ELPC also filed appeals of the PUCO's order. On January 24, 2018, the Supreme Court of Ohio reversed the PUCO order finding that the order violated the rule against prohibiting retroactive ratemaking. On February 5, 2018, the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition on February 15, 2018.

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. On March 29, 2017, the PUCO issued a Second Entry on Rehearing that granted, in part, the applications for rehearing filed by FES and other parties, finding that the PUCO's guidelines regarding fixed-price contracts should not apply to large mercantile customers. This finding changes the original order, which applied the guidelines to all customers, including mercantile customers. The PUCO also reaffirmed several provisions of the original order, including that the fixed-price guidelines only apply on a going-forward basis and not to existing contracts and that regulatory-out clauses in contracts are permissible.

On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan. The DPM Plan is a portfolio of approximately $450 million in distribution platform investment projects, which are designed to modernize the Ohio Companies' distribution grid, prepare it for further grid modernization projects, and provide customers with immediate reliability benefits. The Ohio Companies have requested that the PUCO issue an order approving the DPM Plan and associated cost recovery no later than May 2, 2018, so that the Ohio Companies can expeditiously commence the DPM Plan and customers can begin to realize the associated benefits.

On January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act and determine the appropriate course of action to pass benefits on to customers. The Ohio Companies must establish a regulatory liability, effective January 1, 2018, for the estimated reduction in federal income tax resulting from the Tax Act, and filed comments on February 15, 2018, explaining that customers will save nearly $40 million annually as a result of updating tariff riders for the tax rate changes and that the Ohio Companies' base distribution rates are not impacted by the Tax Act changes because they are frozen through May 2024.

PENNSYLVANIA

The Pennsylvania Companies operate under 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 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. The DSPs include modifications to the Pennsylvania Companies' POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

On December 11, 2017, the Pennsylvania Companies filed DSPs for the June 1, 2019 through May 31, 2023 delivery period. Under the 2019-2023 DSPs, the supply is proposed to be provided by wholesale suppliers through a mix of 3, 12 and 24-month energy contracts, as well as two RFPs for 2-year SREC contracts for ME, PN and Penn. The 2019-2023 DSPs as proposed also include modifications to the Pennsylvania Companies' POR programs in order to continue their clawback pilot program as a long-term, permanent program term. The 2019-2023 DSPs also introduce a retail market enhancement rate mechanism designed to stimulate residential customer shopping, and modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW. A hearing has been scheduled for April 10-11, 2018, and the PPUC is expected to issue a final order on these DSPs by mid-September 2018.

The Pennsylvania Companies operate under rates that were approved by the PPUC on January 19, 2017, effective as of January 27, 2017. These rates provide annual increases in operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are intended to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements.

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. 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 February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the remaining period of 2018 to 2020, as modified, are: WP $50.1 million; PN $44.8 million; Penn $33.2 million; and ME $51.3 million.

On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery, which were approved by the PPUC on June 9, 2016, and went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. On January 19, 2017, in the PPUC’s order approving the Pennsylvania Companies’ general rate cases, the PPUC added an additional issue to the DSIC proceeding to include whether ADIT should be included in DSIC calculations. On

February 2, 2017, the parties to the DSIC proceeding submitted a Joint Settlement to the ALJ that resolved the issues that were pending from the order issued on June 9, 2016, which is pending PPUC approval. The ADIT issue is subject to further litigation and a hearing was held on May 12, 2017. On August 31, 2017, the ALJ issued a decision recommending that the complaint of the Pennsylvania OCA be granted by the PPUC such that the Pennsylvania Companies reflect all federal and state income tax deductions related to DSIC-eligible property in the currently effective DSIC rates. If the decision is approved by the PPUC, the impact is not expected to be material to FirstEnergy. The Pennsylvania Companies filed exceptions to the decision on September 20, 2017, and reply exceptions on October 2, 2017.

On February 12, 2018, the PPUC initiated a proceeding to determine the effects of the Tax Act on the tax liability of utilities and the feasibility of reflecting such impacts in rates charged to customers. By March 9, 2018, the Pennsylvania Companies must submit information to the PPUC to calculate the net effect of the Tax Act on income tax expense and rate base, and comments addressing whether rates should be adjusted to reflect the tax rate changes, and if so, how and when such modifications should take effect.

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 September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of 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. On December 15, 2017, the WVPSC approved MP's and PE's proposed annual decrease in their EE&C rates, effective January 1, 2018, which is not material to FirstEnergy.

On December 9, 2016, the WVPSC approved the annual ENEC case for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, resulting in an increase in the ENEC rate of $25 million annually beginning January 1, 2017. In addition, ENEC rates will be maintained at the same level for a two year period.

On December 30, 2015, MP and PE 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. On December 16, 2016, MP issued an RFP to address its generation shortfall, 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. AE Supply was the winning bidder of the RFP to address MP’s generation shortfall and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire AE Supply’s Pleasants Power Station (1,300 MWs) for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals. In addition, on March 7, 2017, MP and PE filed an application with the WVPSC and MP and AE Supply filed an application with FERC requesting authorization for such purchase. Various intervenors filed protests challenging the RFP and requesting FERC deny the application, set it for hearing to allow discovery into the RFP process, or delay an order pending the conclusion of the WVPSC proceeding. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate that the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC’s affiliate cross-subsidization analysis. In the order FERC also revised and clarified certain details of its standards for the review of transactions resulting from competitive solicitations, and concluded that MP's RFP did not meet the revised and clarified standards. FERC allowed that MP may submit a future application for a transaction resulting from a new RFP. The WVPSC issued its order on January 26, 2018, denying the petition as filed but granting the transfer of Pleasants Power Station under certain conditions, which included MP assuming significant commodity risk. MP, PE and AE Supply have determined not to seek rehearing at FERC in light of the adverse decisions at FERC and the WVPSC. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement. With respect to the Bath County RFP, MP does not plan to move forward with that sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

On September 1, 2017, MP and PE filed with the WVPSC for a reconciliation of their VMS to confirm that rate recovery matches VMP costs and for a regular review of that program. MP and PE proposed a $15 million annual decrease in VMS rates effective January 1, 2018, and an additional $15 million decrease in rates for 2019. This is an overall decrease in total revenue and average rates of 1%. On December 15, 2017, the WVPSC issued an order adopting a unanimous settlement without modification.

On January 3, 2018, the WVPSC initiated a proceeding to investigate the effects of the Tax Act on the revenue requirements of utilities. MP and PE must track the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018, and file written testimony explaining the impact of the Tax Act on federal income tax and revenue requirements by May 30, 2018. On January 26, 2018, the WVPSC issued an order clarifying that regulatory accounting should be implemented as of January 1, 2018, including the recording of any regulatory liabilities resulting from the Tax Act.

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 certain of its subsidiaries, AE Supply, FENOC, ATSI, MAIT 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, but subsequently agreed to suspend it and advised FERC of this course of action.

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. On August 30, 2017, the generation owners requested expedited action by FERC. 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. FirstEnergy and certain of the other parties responded to such opposition. On October 20, 2017, the settling and non-opposing parties requested expedited action by FERC. 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, ATSI resolved a dispute regarding responsibility for certain costs for the “Michigan Thumb” transmission project. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. 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. The MISO TOs subsequently filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened and participated in the proceedings on behalf of ATSI, the Ohio Companies and Penn. On June 21, 2017, the Sixth Circuit issued its decision denying the MISO TOs' appeal request. MISO and the MISO TOs did not seek review by the U.S. Supreme Court, effectively resolving the dispute over the "Michigan Thumb" transmission project. 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 MVP costs and "legacy RTEP" transmission projects cannot be predicted at this time.

Transfer of Transmission Assets to MAIT

Following receipt of necessary regulatory approvals, on January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and transmission asset contributions. MAIT, a transmission-only subsidiary of FET, owns and operates all of the FERC-jurisdictional transmission assets previously owned by ME and PN. Subsequently, on March 13, 2017, FERC issued an order authorizing MAIT to issue short- and long-term debt securities, permitting MAIT to participate in the FirstEnergy regulated companies’ money pool for working capital, to fund day-to-day operations, support capital investment and establish an actual capital structure for ratemaking purposes.

MAIT Transmission Formula Rate

On October 28, 2016, as amended on January 10, 2017, 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 February 1, 2017. 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. On March 10, 2017, FERC issued an order accepting the MAIT formula transmission rate for filing, suspending the formula transmission rate for five months to become effective July 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, MAIT requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. MAIT’s rates went into effect on July 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC. The settlement agreement provides for certain changes to MAIT's formula rate, changes MAIT's ROE from 11% to 10.3%, sets the recovery amount for certain regulatory assets, and establishes that MAIT's capital structure will not exceed 60% equity over the period ending December 31, 2021. The settlement agreement further provides that the ROE and the 60% cap on the equity component of MAIT's capital structure will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2022. The settlement agreement currently is pending at FERC. As a result of the settlement agreement, MAIT recognized a pre-tax impairment charge of $13 million in the third quarter of 2017.

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. 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 March 10, 2017, FERC issued an order accepting the JCP&L formula transmission rate for filing, suspending the transmission rate for five months to become effective June 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, JCP&L requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. JCP&L’s rates went into effect on June 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On December 21, 2017, JCP&L and certain parties filed a settlement agreement with FERC. The settlement agreement provides for a $135 million stated annual revenue requirement for Network Integration Transmission Service and an average of $20 million stated annual revenue requirement for certain projects listed on the PJM Tariff where the costs are allocated in part beyond the JCP&L transmission zone within the PJM Region. The revenue requirements are subject to a moratorium on additional revenue requirements proceedings through December 31, 2019, other than limited filings to seek recovery for certain additional costs. Also on December 21, 2017, JCP&L filed a motion for authorization to implement the settlement rate on an interim basis. On December 27, 2017, FERC granted the motion authorizing JCP&L to implement the settlement rate effective January 1, 2018, pending a final commission order on the settlement agreement. The settlement agreement is pending at FERC. As a result of the settlement agreement, JCP&L recognized a pre-tax impairment charge of $28 million in the fourth quarter of 2017.

DOE NOPR: Grid Reliability and Resilience Pricing

On September 28, 2017, the Secretary of Energy released a NOPR requesting FERC to issue rules directing RTOs to incorporate pricing for defined “eligible grid reliability and resiliency resources” into wholesale energy markets. Specifically, as proposed, RTOs would develop and implement tariffs providing a just and reasonable rate for energy purchases from eligible grid reliability and resiliency resources and the recovery of fully allocated costs and a fair ROE. The NOPR followed the August 23, 2017, release of the DOE’s study regarding whether federally controlled wholesale energy markets properly recognize the importance of coal and nuclear plants for the reliability of the high-voltage grid, as well as whether federal policies supporting renewable energy sources have harmed the reliability of the energy grid. The DOE requested for the final rules to be effective in January 2018.

On October 2, 2017, FERC established a docket and requested comments on the NOPR. FESC and certain of its affiliates submitted comments and reply comments. On January 8, 2018, FERC issued an order terminating the NOPR proceeding, finding that the NOPR did not satisfy the statutory threshold requirements under the FPA for requiring changes to RTO/ISO tariffs to address resilience concerns. FERC in its order instituted a new administrative proceeding to gather additional information regarding resilience issues, and directed that each RTO/ISO respond to a provided list of questions. There is no deadline or requirement for FERC to act in this new proceeding. At this time, we are uncertain as to the potential impact that final action by FERC, if any, would have on FES and our strategic options, and the timing thereof, with respect to the competitive business.

Competitive Generation Asset Sale

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments and through multiple, independent closings. On December 13, 2017, AE Supply completed the sale of the natural gas generating plants with net proceeds, subject to post-closing adjustments, of approximately $388 million. The sale of AE Supply's interests in the Bath County hydroelectric power station and the Buchanan Generating facility is expected to generate net proceeds of $375 million and is anticipated to close in the first half of 2018, subject in each case to various customary and other closing conditions, including, without limitation, receipt of regulatory approvals.

As part of the closing of the natural gas generating plants, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement.

With the sale of the gas plants completed, upon the consummation of the sale of AGC's interest in the Bath County hydroelectric power station or the sale or deactivation of the Pleasants Power Station, AE Supply is obligated under the amended and restated purchase agreement and AE Supply's applicable debt agreements to satisfy and discharge approximately $305 million of currently outstanding senior notes, as well as its $142 million of pollution control notes and AGC's $100 million senior notes, which are expected to require the payment of "make-whole" premiums currently estimated to be approximately $95 million based on current interest rates.

On October 20, 2017, the parties filed an application with the VSCC for approval of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station. On December 12, 2017, FERC issued an order authorizing the partial transfer of the related hydroelectric license for Bath County under Part I of the FPA. In December 2017, AGC, AE Supply and MP filed with FERC and AGC and AE Supply filed with the VSCC, applications for approval of AGC redeeming AE Supply’s shares in AGC upon consummation of the Bath County transaction. On February 2, 2018, the VSCC issued an order finding that approval of the proposed stock redemption is not required, and on February 16, 2018, FERC issued an order authorizing the redemption. Upon the consummation of the redemption, AGC will become a wholly-owned subsidiary of MP.

On December 28, 2017, FERC issued an order authorizing the sale of BU Energy’s Buchanan interests. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once the sales are consummated. There can be no assurance that all regulatory approvals will be obtained and/or all closing conditions will be satisfied or that the remaining transactions will be consummated.

As a result of the amended asset purchase agreement, CES recorded non-cash pre-tax impairment charges of $193 million in 2017, reflecting the $825 million purchase price as well as certain purchase price adjustments based on timing of the closing of the transaction.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. 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 hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017, and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC, seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers commented on the compliance filing, alleging inaccuracies in and lack of transparency of data and information in the compliance filing, and requested that PATH be directed to recalculate the refund provided in the filing. PATH responded to these comments in a filing that was submitted on May 22, 2017. On July 27, 2017, FERC Staff issued a letter to PATH requesting additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH filed its response on September 27, 2017. FERC orders on PATH's requests for rehearing and compliance filing remain pending.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and certain of its subsidiaries, Buchanan Generation and Green Valley 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 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. On July 27, 2017, FERC accepted the triennial filing as submitted.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition. 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 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 the EPA’s regulatory approach under CSAPR, but questioning whether the EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. The 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. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, the EPA’s reconsideration of the CSAPR update rule and how the

EPA and the states ultimately 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. The EPA missed the October 1, 2017, deadline and has not yet promulgated the attainment designations. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. On December 5, 2017, fourteen states and the District of Columbia filed complaints in the U.S. District Court of Northern California seeking an order that the EPA promulgate the attainment designations for 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, but has not taken any further action. On January 2, 2018, the State of Delaware provided the EPA a notice required at least 60 days prior to filing a suit seeking to compel the EPA to either approve or deny the August 2016 CAA Section 126 petition. 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, but has not taken any further action. On September 27, 2017, and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the U.S. District Court for the District of Maryland seeking an order that the EPA either approve or deny the CAA Section 126 petition of November 16, 2016. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

MATS imposed emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired EGUs effective in April 2015 with averaging of emissions from multiple units located at a single plant. The majority of FirstEnergy's MATS compliance program and related costs have been completed.

On August 3, 2015, FG, a wholly owned 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 arose 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. 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 hearing in November and December 2016. On April 12, 2017, the arbitration panel ruled on liability in favor of BNSF and CSX. In the liability award, the panel found, among other things, that FG’s demand for declaratory judgment that force majeure excused FG’s performance was denied, that FG breached and repudiated the coal transportation contract and that the panel retains jurisdiction of claims for liquidated damages for the years 2015-2025. On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to this consolidated proceeding on the terms and conditions set forth below. Pursuant to the settlement agreement, FG will pay CSX and BNSF an aggregate amount equal to $109 million, which is payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provides that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. Further, FE and FG, and CSX and BNSF, agreed to release, waive and discharge each other from any further obligations under the claims covered by the settlement agreement upon payment in full of the settlement amount. Until such time, CSX and BNSF will retain the claims covered by the settlement agreement and in the event of a bankruptcy proceeding with respect to FG, to the extent the remaining settlement payments are not paid in full by FG or FE, CSX and BNSF shall be entitled to seek damages for such claims in an amount to be determined by the arbitration panel or otherwise agreed by the parties.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS which 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 generating station. 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 liquidated damages through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. The arbitration hearing is scheduled for June 2018. The parties have exchanged settlement proposals to resolve all claims related to this proceeding, however, discussions have been terminated and settlement is unlikely. FirstEnergy and FES recorded a pre-tax charge of $116 million in 2017 based on an estimated range of losses regarding the ongoing litigation with respect to this agreement. If the case proceeds to arbitration, the amount of damages owed to BNSF and NS could be materially higher and may cause FES to seek protection under U.S. bankruptcy laws. FG intends to vigorously assert its position in this arbitration proceeding, and 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.

As to a specific coal supply agreement, AE Supply, the party thereto, asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, on January 15, 2015, Tunnel Ridge, LLC, the coal supplier, commenced litigation in the Court of Common Pleas of Allegheny County, Pennsylvania, alleging AE Supply did not have sufficient justification to terminate the agreement and seeking damages for the difference between the market and contract price of the coal, or lost profits plus incidental damages. AE Supply filed an answer denying any liability related to the termination. On May 1, 2017, the complaint was amended to add FE, FES and FG, although not parties to the underlying contract, as defendants and to seek additional damages based on new claims of fraud, unjust enrichment, promissory estoppel and alter ego. On June 27, 2017, after oral argument, defendants' preliminary objections to the amended complaint were denied. On February 18, 2018, the parties reached an agreement in principle settling all claims in dispute. The agreement in principle includes, among other matters, a $93 million payment by AE Supply, as well as certain coal supply commitments for Pleasants Power Station during its remaining operation by AE Supply. Certain aspects of the final settlement agreement will be guaranteed by FE, including the $93 million payment.

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, the 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, the 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 U.S. 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 CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel-fired EGUs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired EGUs. Numerous states and private parties filed appeals and motions to stay the CPP with 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. On March 28, 2017, an executive order, entitled "Promoting Energy Independence and Economic Growth," instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, 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 GHG emissions by 26 to 28 percent below 2005 levels by 2025 and in September 2016, 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 became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. 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. Depending on any final action taken by the states with respect to impingement and entrainment, 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 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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. 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 CCRs, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, 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. The Sierra Club's Notices of Appeal before the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility were resolved through a Consent Adjudication between FG, PA DEP and the Sierra Club requiring operational changes that became effective November 3, 2017.

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, 2017, 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 $125 million have been accrued through December 31, 2017. Included in the total are accrued liabilities of approximately $80 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2017, FirstEnergy had approximately $2.7 billion (FES $1.9 billion) invested in external trusts to be used for the decommissioning and environmental remediation of its nuclear generating facilities. The values of FirstEnergy's NDTs also fluctuate based on market conditions. If the values 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.

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. In 2017, FENOC commenced a multi-year effort to implement repairs to the shield building. In addition to these ongoing repairs, FENOC intends to submit a license amendment application to the NRC to reconcile the shield building laminar cracking concern.

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. So long as FES remains in the unregulated companies' money pool, the $500 million secured line of credit with FE discussed above provides FES the needed liquidity in order for FES to satisfy its nuclear support obligations 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, AGC, ATSI, MAIT and TrAIL 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.

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 pre-tax pension and OPEB mark-to-market adjustment charged to earnings for the years ended December 31, 2017, 2016, and 2015 were $141 million, $147 million, and $242 million, 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 3.75%, 4.25% and 4.50% as of December 31, 2017, 2016 and 2015, respectively. The assumed discount rates for OPEB were 3.50%, 4.00% and 4.25% as of December 31, 2017, 2016 and 2015, 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 2017, FirstEnergy's qualified pension and OPEB plan assets experienced gains of $999 million or 15.1% compared to gains of $472 million, or 8.2% in 2016 and losses of $(172) million, or (2.7)% in 2015 and assumed a 7.50% rate of return on plan assets in 2017 and 2016 and a 7.75% expected rate of return in 2015 which generated $478 million, $429 million and $476 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 2018 is 7.50%.

During 2017, the Society of Actuaries released its updated mortality improvement scale for pension plans, MP-2017, incorporating three additional years of SSA data on U.S. population mortality. MP-2017 incorporates SSA mortality data from 2013 to 2015 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. Due to the additional years of data on population mortality, the RP2014 mortality table with the projection scale MP-2017 was utilized to determine the 2017 benefit cost and obligation as of December 31, 2017 for the FirstEnergy pension and OPEB plans. The impact of using the projection scale MP-2017 resulted in a decrease in the projected pension benefit obligation of $62 million and was included in the 2017 pension and OPEB mark-to-market adjustment.

Based on discount rates of 3.75% for pension, 3.50% for OPEB and an estimated return on assets of 7.50%, FirstEnergy expects its 2018 pre-tax net periodic benefit credit (including amounts capitalized) to be approximately $50 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2018). 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, 2017.

Postemployment Benefits Expense (Credits)	2017	2016	2015
	(In millions)		
Pension	$247	$277	$316
OPEB	(45)	(40)	(61)
Total	$202	$237	$255

Health care cost trends continue to increase and will affect future OPEB costs. The composite health care trend rate assumptions were approximately 6.0-5.5% in 2017 and 2016, 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 2018 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%	$315	$ 18	$333
Long-term return on assets	Decrease by .25%	$19	$ 1	$20
Health care trend rate	Increase by 1.0%	N/A	$ 21	$21

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 Sales and Impairments," for impairments recognized in 2017 and 2016.

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, considering the expected timing of settlement of the ARO based on the expected economic useful life of the plants (including the likelihood that the facilities will be deactivated before the end of their estimated useful lives). 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, 2017, 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.

On December 22, 2017, the President signed into law the Tax Act. Substantially all of the provisions of the Tax Act are effective for taxable years beginning after December 31, 2017. The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and includes specific provisions related to regulated public utilities including FirstEnergy's regulated distribution and transmission subsidiaries. The more significant changes that impact FirstEnergy included in the Tax Act are the following:

- Reduction of the corporate federal income tax rate from 35% to 21%, effective in 2018;
- Full expensing of qualified property, excluding rate regulated utilities, through 2022 with a phase down beginning in 2023;
- Limitations on interest deductions with an exception for rate regulated utilities;
- Limitation of the utilization of federal NOLs arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward;
- Repeal of the corporate AMT and allowing taxpayers to claim a refund on any AMT credit carryovers.

The most significant change that impacts FirstEnergy in the current year is the reduction of the corporate federal income tax rate. Other provisions are not expected to have a significant impact on the financial statements, but may impact the effective tax rate in future years. Under US GAAP, specifically ASC Topic 740, Income Taxes, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted, or December 22, 2017, for the Tax Act. ASC 740 also requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Thus, at the date of enactment, FirstEnergy's deferred taxes were re-measured based upon the new tax rate, which resulted in a material decrease to FirstEnergy's net deferred income tax liabilities. For FirstEnergy's unregulated operations, the change in deferred taxes are recorded as an adjustment to FirstEnergy's deferred income tax provision. FirstEnergy's regulated entities recorded a corresponding net regulatory liability to the extent the change in deferred taxes would result in amounts previously collected from utility customers to be subject to refunds to such customers, generally through reductions in future rates. All other amounts were recorded as an adjustment to FirstEnergy's regulated entities' deferred income tax provision.

FirstEnergy has completed its assessment of the accounting for certain effects of the provisions in the Tax Act, and as allowed under SEC Staff Accounting Bulletin 118 (SAB 118), has recorded provisional income tax amounts as of December 31, 2017 related to depreciation for which the impacts of the Tax Act could not be finalized, but for which a reasonable estimate could be determined. Under the new law, property acquired and placed into service after September 27, 2017, will be eligible for full expensing for all taxpayers other than regulated utilities. As a result, FirstEnergy will need to evaluate the contractual terms of its capital expenditures to determine eligibility for full expensing. As of December 31, 2017, FirstEnergy has not yet completed this analysis, but has recorded a reasonable estimate of the effects of these changes based on capital costs incurred prior to year-end. In addition, SAB 118 allows for a measurement period for companies to finalize the provisional amounts recorded as of December 31, 2017. FirstEnergy expects to record any final adjustments to the provisional amounts by the fourth quarter of 2018, which could result in a material impact to FirstEnergy’s income tax provision or financial position.

FirstEnergy’s assessment of accounting for the Tax Act are based upon management’s current understanding of the Tax Act. However, it is expected that further guidance will be issued during 2018, which may result in adjustments that could have a material impact to FirstEnergy’s future results of operations, cash flows, or financial position.

As a result of the Tax Act, FirstEnergy recognized a non-cash charge to income tax expense of $1.2 billion (FES - $1.1 billion) and resulted in excess deferred taxes of $2.3 billion for the regulated businesses, of which the revenue impact was recorded as a regulatory liability. These adjustments had no impact on our 2017 cash flows.

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, 2017, 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. Key factors used in the assessment include: growth rates, interest rates, expected capital expenditures, utility sector market performance and other market considerations. It was determined that the fair values 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 Sales and Impairments," for further discussion of CES goodwill impairment charge recognized in 2016.

NEW ACCOUNTING PRONOUNCEMENTS

ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting" (Issued March 2016): ASU 2016-09 simplifies several aspects of the accounting for employee share-based payments. The new guidance requires all income tax effects of awards to be recognized in the income statement when the awards vest or are settled. It also does not require liability accounting when an employer repurchases more of an employee’s shares for tax withholding purposes. FirstEnergy adopted ASU 2016-09 on January 1, 2017. Upon adoption, FirstEnergy elected to account for forfeitures as they occur. The change was applied on a modified retrospective basis with a cumulative effect adjustment to retained earnings of approximately $6 million as of January 1, 2017. Additionally, FirstEnergy retrospectively applied the cash flow presentation requirement to present cash paid to tax authorities when shares are withheld to satisfy statutory tax withholding obligations as financing activities by reclassifying $12 million and $13 million from operating activities to financing activities in the 2016 and 2015 Consolidated Statements of Cash Flows, respectively.

ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments" (Issued August 2016): The standard is intended to eliminate diversity in practice in how certain cash receipts and cash payments are presented and classified in the Consolidated Statements of Cash Flows, including the presentation of debt prepayment or debt extinguishment costs, all of which will be classified as financing activities. ASU 2016-15 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. FirstEnergy early adopted this ASU as of January 1, 2017. There was no impact to prior periods.

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB was not adopted in 2017. Unless otherwise indicated, FirstEnergy is currently assessing the impact such guidance may have on its financial statements and disclosures, as well as the potential to early adopt where applicable. FirstEnergy has assessed other FASB issuances of new standards not described below and has not included these standards based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting.

ASU 2014-09, "Revenue from Contracts with Customers" (Issued May 2014 and subsequently updated to address implementation questions): The new revenue recognition guidance: establishes a new control-based revenue recognition model, changes the basis for deciding when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific topics and expands and improves disclosures about revenue. FirstEnergy has evaluated its revenues and the new guidance will have limited impacts to current revenue recognition practices upon adoption on January 1, 2018. As part of the adoption, FirstEnergy elected to apply the new guidance on a modified retrospective basis. FirstEnergy will not record a cumulative adjustment to retained earnings for initially applying the new guidance as no revenue recognition differences were identified in the timing or amount of revenue. In addition, upon adoption, certain immaterial financial statement presentation changes will be implemented. FirstEnergy expects to disaggregate revenue by type of service in future revenue disclosures.

ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities" (issued January 2016): ASU 2016-01 primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. Upon adoption, January 1, 2018, FirstEnergy will recognize all gains and losses for equity securities in income with the exception of those that are accounted for under the equity method of accounting. The NDT's equity portfolios of JCP&L, ME and PN will not be impacted as unrealized gains and losses will continue to be offset against regulatory assets or liabilities. As a result of adopting the standard, FirstEnergy and FES will record a cumulative effect adjustment to retained earnings of $115 million (pre-tax) on January 1, 2018 representing unrealized gains on equity securities that were previously recorded to AOCI.

ASU 2016-02, "Leases (Topic 842)" (Issued February 2016) and ASU 2018-01,"Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842" (Issued January 2018): ASU 2016-02 will require organizations that lease assets with lease terms of more than 12 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. ASU 2018-01 (same effective date and transition requirements as ASU 2016-02) provides an optional transition practical expedient that, if elected, would not require an entity to reconsider its accounting for existing land easements that are not currently accounted for under the old leases standard. FirstEnergy does not plan to adopt these standards early. 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 expects an increase in assets and liabilities, however, it is currently assessing the impact on its Consolidated Financial Statements. This assessment includes monitoring utility industry implementation guidance. FirstEnergy is in the process of conducting outreach activities across its business units and analyzing its lease population. In addition, it has begun implementation of a third-party software tool that will assist with the initial adoption and ongoing compliance.

ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments” (issued June 2016): ASU 2016-13 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.

ASU 2016-16, "Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory" (issued October 2016): 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 will not be impacted upon its adoption of this ASU on January 1, 2018.

ASU 2016-18, "Restricted Cash" (issued November 2016): ASU 2016-18 addresses the presentation of changes in restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is required to be applied retrospectively. In its first quarter 2018 Form 10-Q, FirstEnergy will show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. In addition, FirstEnergy will disclose the nature of its restricted cash and restricted cash equivalent balances within the footnotes.

ASU 2017-01, "Business Combinations: Clarifying the Definition of a Business" (Issued January 2017): ASU 2017-01 assists entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. The ASU will be applied prospectively to any transactions occurring within the period of adoption. FirstEnergy will not early adopt this standard.

ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (Issued March 2017): ASU 2017-07 requires entities to retrospectively (1) disaggregate the current-service-cost component from the other components of net benefit cost (the “other components”) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. As a result of the retrospective presentation, FirstEnergy will reclassify approximately $62 million of non-service costs, excluding the annual mark-to-market, to Other Income/Expense related to the fiscal year 2017 within the 2018 financial statements. In addition, ASU 2017-07 requires service costs to be capitalized as appropriate and non-service costs to be charged to earnings. FirstEnergy will present non-service costs in the caption “Miscellaneous Income” with the exception of the annual mark-to-market adjustment which will be disclosed separately.

ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" (Issued February 2018): ASU 2018-02 allows entities to reclassify from AOCI to retained earnings stranded tax effects resulting from the Tax Act. ASU 2018-02 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2018. Early adoption of the ASU is permitted including adoption in any interim period. ASU 2018-02 should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the income tax rate change resulting from the Tax Act is recognized. FirstEnergy did not adopt this ASU as of December 31, 2017.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

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, which are operated by FENOC. 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 terminated the PSA effective April 1, 2017.

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 are expected to generate approximately 40-45 million MWHs annually, with up to an additional five million MWHs available from purchased power agreements for wind, solar, FES' entitlement in OVEC.

On January 10, 2018, a fire damaged the scrubber, stack and other plant property and systems associated with Bruce Mansfield Units 1 and 2. Evaluation of the extent of the damage, which may be significant, to the scrubber, stack and other plant property and systems associated with Units 1 and 2 is underway and is expected to take several weeks. Unit 3, which had been off-line for maintenance, was unaffected by the fire. The affected plant property and systems are insured and management is working with the insurance carriers to complete the assessment. At this time management is unable to estimate the financial effect of the fire on Units 1 and 2.

In November 2016, FirstEnergy announced a strategic review to exit its commodity-exposed generation at CES, which is primarily comprised of the operations of FES. The strategic options to exit the remaining portion of the CES portfolio, which is primarily at FES, are limited. The credit quality of FES, including its unsecured debt rating of Ca at Moody’s, C at S&P, and C at Fitch and the negative outlook from Moody’s and S&P, has challenged its ability to consummate asset sales. Furthermore, the inability to obtain legislative support under the Department of Energy’s recent NOPR, which was rejected by FERC, limits FES’ strategic options to plant deactivations, restructuring its debt and other financial obligations with its creditors, and/or to seek protection under U.S. bankruptcy laws.

As part of the strategic review, FES evaluated its options with respect to its nuclear power plants. Factors considered as part of this review included current and forecasted market conditions, such as wholesale power and capacity prices, legislative and regulatory solutions that recognize their environmental and energy security benefits, and many other factors, including the significant capital and operating costs associated with operating a safe and reliable nuclear fleet. Based on this analysis, given the weak power and capacity price environment and the lack of legislative and regulatory solutions achieved to date, FES concluded that it would be increasingly difficult to operate these facilities in this environment and absent significant change concluded that it was probable that the facilities would be either deactivated or sold before the end of their estimated useful lives. As a result, FES recorded a pre-tax charge of $2.0 billion in the fourth quarter of 2017 to fully impair the nuclear facilities, including the generating plants and nuclear fuel as well as to reserve against the value of materials and supplies inventory and to increase its asset retirement obligation. For additional information see Note 2, "Asset Sales and Impairments."

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of January 31, 2018, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. As previously disclosed, FES has $515 million of maturing debt in 2018, (excluding intra-company debt), beginning with a $100 million principal payment due April 2, 2018. Based on FES' current senior unsecured debt rating, capital structure and long-term cash flow projections, the debt maturities are unlikely to be refinanced. Although management continues to explore cost reductions and other options to improve cash flow, these 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.

For additional information with respect to FES, please see the information contained under "Risk Factors," in Part I, Item 1A of this Form 10-K and 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," "Executive Summary," "Capital Resources and Liquidity," "Guarantees and Other Assurances," "Off-Balance Sheet Arrangements," "Market Risk Information," "Credit Risk," "New Accounting Pronouncements," and "Outlook."

Results of Operations

Operating results increased $3,064 million, in 2017 as compared to 2016, primarily due to lower asset impairment and plant exit costs, as further discussed below in Note 2, "Asset Sales and Impairments," and lower depreciation expense, partially offset by a charge to Income tax expense of $1,067 million as a result of the Tax Act, pre-tax charges of $225 million associated with estimated losses on long-term coal transportation contract disputes, as discussed in "Outlook - Environmental Matters," above, higher non-cash mark-to-market losses on commodity contract positions, lower capacity revenue, and the impact of lower contract sales.

Revenues —

Total revenues decreased $1,300 million in 2017, as compared to 2016, primarily due to lower capacity auction prices, lower contract sales volumes at lower prices, and lower net gains on financially settled contracts.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2017	2016	Decrease
	(In millions)		
Contract Sales:			
Direct	$735	$812	$(77)
Governmental Aggregation	396	814	(418)
Mass Market	127	169	(42)
POLR	504	583	(79)
Structured Sales	337	440	(103)
Total Contract Sales	2,099	2,818	(719)
Wholesale	899	1,350	(451)
Transmission	35	70	(35)
Other	65	160	(95)
Total Revenues	$3,098	$4,398	$(1,300)

MWH Sales by Channel	For the Years Ended December 31 2017	2016	Decrease
	(In thousands)		
Contract Sales:			
Direct	15,157	15,310	(1.0)%
Governmental Aggregation	7,431	13,730	(45.9)%
Mass Market	1,867	2,431	(23.2)%
POLR	9,140	9,969	(8.3)%
Structured Sales	8,805	11,004	(20.0)%
Total Contract Sales	42,400	52,444	(19.2)%

Wholesale	13,639	13,812	(1.3)%
Total MWH Sales	56,039	66,256	(15.4)%

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

MWH Sales Channel:	Source of Change in Revenues Decrease Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(8)	$(69)	$ —	$ —	$(77)
Governmental Aggregation	(373)	(45)	—	—	(418)
Mass Market	(40)	(2)	—	—	(42)
POLR	(49)	(30)	—	—	(79)
Structured Sales	(89)	(14)	—	—	(103)
Wholesale	(6)	(6)	(156)	(283)	(451)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract in 2016. The Direct, Governmental Aggregation, and Mass Market customer base was approximately 900,000 as of December 31, 2017, compared to 1.1 million as of December 31, 2016. Although unit pricing was lower year-over-year in the Direct, Governmental Aggregation and Mass Market channels, the decrease was primarily attributable to lower capacity rates, as discussed below, which is a component of the retail price.

The decrease in POLR revenue of $79 million was primarily due to both lower volumes and lower unit prices. Structured revenue decreased $103 million, primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues decreased $451 million, primarily due to a decrease in capacity revenue from lower capacity auction prices and lower net gains on financially settled contracts.

Transmission revenue decreased $35 million, primarily due to lower congestion revenues associated with less volatile market conditions.

Other revenues decreased $95 million, primarily due to lower lease revenues from the expiration of a nuclear sale-leaseback agreement. FES earned lease revenue associated with the lessor equity interests it had purchased in sale-leaseback transactions, one of which expired in June 2017 and another in May 2016.

Operating Expenses —

Total operating expenses decreased $7,631 million in 2017 as compared to 2016.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2017 compared with 2016:

Operating Expense	Source of Change Increase (Decrease) Volumes	Prices	Loss on Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(147)	$ 7	$ (58)	$ —	$(198)
Nuclear Fuel	6	11	—	—	17

Affiliated Purchased Power	(134)	23	(312)	—	(423)
Non-affiliated Purchased Power	(18)	9	(114)	(269)	(392)

Fossil fuel costs decreased $198 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts recognized in 2016, as well as lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as discussed above, partially offset by higher unit costs. Nuclear fuel costs increased $17 million, primarily due to higher generation at higher unit costs.

Affiliated purchased power costs decreased $423 million, primarily resulting from the termination of the AE Supply PSA, effective April 1, 2017, and the expiration of a nuclear sale-leaseback agreement.

Non-affiliated purchased power costs decreased $392 million due to lower capacity expense ($269 million), lower net losses on financially settled contracts ($114 million) and lower volumes ($18 million), partially offset by higher unit costs ($9 million). The decrease in capacity expense, which is a component of FES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with FES' retail sales obligation. Lower volumes primarily resulted from lower contract sales, as discussed above.

Other operating expenses increased $237 million, in 2017 as compared to 2016, due to the following:

- Charges of $225 million associated with estimated losses on long-term coal transportation contract disputes was recognized in 2017, as discussed in the "Outlook - Environmental Matters" above.
- Nuclear operating and maintenance expenses increased $14 million, primarily as a result of higher employee benefit costs, partially offset by lower refueling outage costs.
- Retirement benefit costs decreased $12 million.
- Transmission expenses decreased $62 million, primarily due to lower contract sales volumes.
- Other operating expenses increased $72 million, primarily due to higher non-cash mark-to-market losses on commodity contract positions, partially offset by the absence of a termination charge associated with an FES Governmental Aggregation customer contract.

The Pension and OPEB mark-to-market adjustment decreased $24 million in 2017. The 2017 adjustment resulted primarily from a 50 bps decrease in the discount rate used to measure benefit obligations, partially offset by higher than expected asset returns.

Depreciation expense decreased $227 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016.
General taxes decreased $30 million, primarily due to lower property taxes and reduced gross receipts taxes associated with lower retail sales volumes.
Impairment of assets and related charges decreased $6,591 million, primarily due to the absence of impairments recognized in 2016 related to goodwill and the competitive generation assets resulting primarily from the strategic review announced in November 2016, partially offset by the impairments recognized in 2017 related to the nuclear generating assets, as further discussed in Note 2, "Asset Sales and Impairments."

Other Expense —

Total other expense decreased $16 million, in 2017 as compared to 2016, primarily due to lower OTTI on NDT investments.

Income Taxes (Benefits) —

Absent the impact from the Tax Act, discussed above, FES’ 2017 effective tax rate on pre-tax losses for 2017 and 2016 was 36.8% and 35.4%, respectively. The change in the effective tax rate resulted primarily from the absence of 2016 charges, including $151 million of valuation allowances recorded against state and local deferred tax assets, that management believes, more likely than not, will not be realized, as well as the impairment of $23 million of goodwill, which was non-deductible for tax purposes.

Changes in Cash Position

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 $727 million during 2017, $786 million during 2016 and $1,152 million during 2015.

2017 compared with 2016

Cash flows from operations decreased $59 million in 2017 compared with 2016. The year-over-year change in cash from operations decreased primarily due to lower receipts resulting from a decrease in capacity revenue and contract sales and timing of working capital.

2016 compared with 2015

Cash flows from operations decreased $366 million in 2016 compared with 2015 due to the following:

- a $138 million cash contribution to the qualified pension plan;
- higher cash collateral postings primarily associated with higher margin requirements by counterparties due to FES' credit downgrading in 2016; partially offset by,
- increased capacity revenues.

Cash Flows From Financing Activities

In 2017, cash used for financing activities was $166 million, compared to cash provided from financing activities of $56 million in 2016, and cash used for financing activities of $273 million in 2015. The following table summarizes new debt financing, redemptions, repayments, short-term borrowings and dividends:

Securities Issued or Redeemed / Repaid	For the Years Ended December 31 2017	2016	2015
	(In millions)		
New Issues			
PCRBs	$—	$471	$341
Redemptions / Repayments			
PCRBs	$(158)	$(484)	$(316)
Senior secured notes	(5)	(23)	(95)
	$(163)	$(507)	$(411)
Short-term borrowings (repayments), net	$4	$101	$(126)
Common stock dividend payments	$—	$—	$(70)

On March 1, 2017, FG retired $28 million of PCRBs at maturity.

On June 1, 2017, FG repurchased approximately $130 million of PCRBs, which were subject to a mandatory put on such date. FG is currently holding these PCRBs indefinitely.

Cash Flows From Investing Activities

Cash used for investing activities in 2017 principally represented cash used for property additions and nuclear fuel. The following table summarizes investing activities for 2017, 2016 and 2015:

Cash Used for Investing Activities	For the Years Ended December 31 2017	2016	2015
	(In millions)		
Property additions	$275	$546	$627
Nuclear fuel	254	232	190
Proceeds from asset sales	—	(9)	(13)
Investments	62	56	68
Other	(29)	17	7

$562	$842	$879

2017 compared with 2016

Cash used for investing activity in 2017 decreased $280 million, compared to 2016, primarily due to lower property additions. Property additions decreased primarily due to lower capital expenditures related to outages and the Mansfield dewatering facility, which was substantially completed in 2016.

2016 compared with 2015

Cash used for investing activity in 2016 decreased $37 million, compared to 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 Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. 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, 2017, are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2018	2019	2020	2021	2022	Thereafter	Total
	(In millions)						
Other external sources[1]	$ 12	$ —	$ —	$ —	$ —	$ —	$ 12
Prices based on models	(2)	—	—	—	—	—	(2)
Total	$ 10	$ —	$ —	$ —	$ —	$ —	$ 10

[1] Primarily represents contracts based on broker and ICE quotes.

FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2017, an increase in commodity prices of 10% would decrease net income by approximately $4 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	2018	2019	2020	2021	2022	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$—	$—	$—	$—	$ —	$ 970	$970	$970
Average interest rate	— %	— %	— %	— %	— %	3.9 %	3.9 %	

Liabilities:								
Long-term Debt:								
Fixed rate	$141	$90	$177	$332	$ —	$ 2,086	$2,826	$1,478
Average interest rate	5.6 %	3.0 %	5.7 %	6.1 %	—%	4.4 %	4.7 %	
Variable rate	$—	$9	$—	$—	$ —	$ —	$9	$9
Average interest rate	— %	1.1 %	— %	— %	—%	— %	1.1 %	

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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 $970 million, $810 million and $73 million, respectively, as of December 31, 2017, excluding $3 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $81 million reduction in fair value as of December 31, 2017. 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. During 2017, FES made no contributions to the NDTs.

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 2017 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 2017.

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 with explanatory going concern paragraph on the Company's 2017 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 2017.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of FirstEnergy Corp. and its subsidiaries as of December 31, 2017 and December 31, 2016, and the related consolidated statements of income (loss), comprehensive income (loss), common stockholders' equity, and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and December 31, 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Emphasis of Matter

As discussed in Note 1 to the consolidated financial statements, FirstEnergy Corp.'s wholly-owned subsidiary, FirstEnergy Solutions Corp. (FES), is facing challenging market conditions impacting FES' liquidity.

Definition and Limitations of Internal Control over Financial Reporting

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 20, 2018

We have served as the Company’s auditor since 2002.

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of FirstEnergy Solutions Corp. and its subsidiaries as of December 31, 2017 and December 31, 2016 and the related statements of income (loss) and of comprehensive income (loss), of common stockholder’s equity (deficit), and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and December 31, 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Substantial Doubt About the Company’s Ability to Continue as a Going Concern

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 consolidated 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 consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Cleveland, Ohio
February 20, 2018

We have served as the Company's auditor since 2007.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(In millions)	For the Years Ended December 31 2017	2016	2015
REVENUES:			
Regulated Distribution	$9,734	$9,629	$9,625
Regulated Transmission	1,325	1,144	1,003
Unregulated businesses	2,958	3,789	4,398
Total revenues*	14,017	14,562	15,026
OPERATING EXPENSES:			
Fuel	1,383	1,666	1,855
Purchased power	3,194	3,843	4,423
Other operating expenses	4,232	3,851	3,740
Pension and OPEB mark-to-market adjustment	141	147	242
Provision for depreciation	1,138	1,313	1,282
Amortization of regulatory assets, net	308	297	172
General taxes	1,043	1,042	978
Impairment of assets and related charges (Note 2)	2,406	10,665	42
Total operating expenses	13,845	22,824	12,734
OPERATING INCOME (LOSS)	172	(8,262)	2,292
OTHER INCOME (EXPENSE):			
Investment income (loss)	98	84	(22)
Impairment of equity method investment (Note 1)	—	—	(362)
Interest expense	(1,178)	(1,157)	(1,132)
Capitalized financing costs	79	103	117
Total other expense	(1,001)	(970)	(1,399)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(829)	(9,232)	893
INCOME TAXES (BENEFITS)	895	(3,055)	315
NET INCOME (LOSS)	$(1,724)	$(6,177)	$578
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:			
Basic	$(3.88)	$(14.49)	$1.37
Diluted	$(3.88)	$(14.49)	$1.37
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	444	426	422
Diluted	444	426	424
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$1.44	$1.44	$1.44

* Includes excise tax collections of $390 million, $406 million and $416 million in 2017, 2016 and 2015, 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)

	For the Years Ended December 31		
(In millions)	2017	2016	2015
NET INCOME (LOSS)	$(1,724)	$(6,177)	$578
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(85)	(59)	(116)
Amortized losses on derivative hedges	10	8	5
Change in unrealized gain on available-for-sale securities	22	55	(11)
Other comprehensive income (loss)	(53)	4	(122)
Income taxes (benefits) on other comprehensive income (loss)	(21)	1	(47)
Other comprehensive income (loss), net of tax	(32)	3	(75)
COMPREHENSIVE INCOME (LOSS)	$(1,756)	$(6,174)	$503

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, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 589	$ 199
Receivables-		
Customers, net of allowance for uncollectible accounts of $51 in 2017 and $53 in 2016	1,463	1,440
Other, net of allowance for uncollectible accounts of $1 in 2017 and 2016	191	175
Materials and supplies, at average cost	463	564
Derivatives	37	140
Collateral	146	176
Prepaid taxes and other	219	256
	3,108	2,950
PROPERTY, PLANT AND EQUIPMENT:		
In service	39,778	43,767
Less — Accumulated provision for depreciation	11,925	15,731
	27,853	28,036
Construction work in progress	1,026	1,351
	28,879	29,387
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,678	2,514
Other	506	512
	3,184	3,026
ASSETS HELD FOR SALE (Note 2)	375	—
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	5,618
Regulatory assets	40	1,014
Other	1,053	1,153
	6,711	7,785
	$ 42,257	$ 43,148
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,082	$ 1,685
Short-term borrowings	300	2,675
Accounts payable	1,027	1,043
Accrued taxes	571	580
Accrued compensation and benefits	336	363
Collateral	39	42
Other	722	738
	4,077	7,126
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 700,000,000 and 490,000,000 shares - 445,334,111 and 442,344,218 shares outstanding as of December 31, 2017 and	44	44

December 31, 2016, respectively		
Other paid-in capital	10,001	10,555
Accumulated other comprehensive income	142	174
Accumulated deficit	(6,262)	(4,532)
Total common stockholders' equity	3,925	6,241
Long-term debt and other long-term obligations	21,115	18,192
	25,040	24,433
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	1,359	3,765
Retirement benefits	3,975	3,719
Regulatory liabilities	2,720	157
Asset retirement obligations	2,515	1,482
Deferred gain on sale and leaseback transaction	723	757
Adverse power contract liability	130	162
Other	1,718	1,547
	13,140	11,589
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16)		
	$ 42,257	$ 43,148

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, 2015	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)	
Pensions 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	
Pensions 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)
Net loss					(1,724)
Amortized gains on derivative hedges, net of $4 million of income taxes				6	
Change in unrealized gain on investments, net of $7 million of income taxes				15	
Pensions and OPEB, net of $32 million of income tax benefits (Note 4)				(53)	
Stock-based compensation			36		
Cash dividends declared on common stock			(639)		
Stock Investment Plan and certain share-based benefit plans	2,989,893		56		
Reclass to liability awards (Note 5)			(7)		
Share-based compensation accounting change (Note 1)					(6)
Balance, December 31, 2017	445,334,111	$ 44	$10,001	$ 142	$ (6,262)

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31 2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$(1,724)	$(6,177)	$578
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	1,700	1,974	1,826
Impairment of assets and related charges (Note 2)	2,406	10,665	42
Investment impairments, including equity method investments	13	21	464
Pension and OPEB mark-to-market adjustment	141	147	242
Deferred income taxes and investment tax credits, net	839	(3,063)	284
Deferred costs on sale leaseback transaction, net	49	49	48
Asset removal costs charged to income	22	54	55
Retirement benefits, net of payments	29	64	(20)
Unrealized (gain) loss on derivative transactions (Note 11)	81	9	(73)
Pension trust contributions	—	(382)	(143)
Gain on sale of investment securities held in trusts	(63)	(50)	(23)
Lease payments on sale and leaseback transaction	(73)	(120)	(131)
Changes in current assets and liabilities-			
Receivables	(39)	(11)	184
Materials and supplies	(6)	41	(15)
Prepaid taxes and other	30	27	(10)
Accounts payable	72	(37)	(243)
Accrued taxes	(9)	61	29
Accrued compensation and benefits	(27)	29	5
Other current liabilities	20	56	69
Cash collateral, net	27	(116)	140
Other	320	142	152
Net cash provided from operating activities	3,808	3,383	3,460
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	4,675	1,976	1,311
Short-term borrowings, net	—	975	—
Redemptions and Repayments-			
Long-term debt	(2,291)	(2,331)	(879)
Short-term borrowings, net	(2,375)	—	(91)
Common stock dividend payments	(639)	(611)	(607)
Other	(72)	(43)	(26)
Net cash used for financing activities	(702)	(34)	(292)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,587)	(2,835)	(2,704)
Nuclear fuel	(254)	(232)	(190)
Proceeds from asset sales	388	15	20

Sales of investment securities held in trusts	2,170	1,678	1,534
Purchases of investment securities held in trusts	(2,268)	(1,789)	(1,648)
Asset removal costs	(172)	(145)	(142)
Other	7	27	8
Net cash used for investing activities	(2,716)	(3,281)	(3,122)
Net change in cash and cash equivalents	390	68	46
Cash and cash equivalents at beginning of period	199	131	85
Cash and cash equivalents at end of period	$589	$199	$131
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: stock contribution to pension plan	$—	$500	$—
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$1,039	$1,050	$1,028
Income taxes, net of refunds	$53	$(16)	$37

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)	2017	2016	2015
STATEMENTS OF INCOME (LOSS)			
REVENUES:			
Electric sales to non-affiliates	$2,667	$3,779	$4,151
Electric sales to affiliates	366	459	666
Other	65	160	188
Total revenues*	3,098	4,398	5,005
OPERATING EXPENSES:			
Fuel	599	780	871
Purchased power from affiliates	201	624	353
Purchased power from non-affiliates	628	1,020	1,684
Other operating expenses	1,514	1,277	1,308
Pension and OPEB mark-to-market adjustment	24	48	57
Provision for depreciation	109	336	324
General taxes	58	88	98
Impairment of assets and related charges (Note 2)	2,031	8,622	33
Total operating expenses	5,164	12,795	4,728
OPERATING INCOME (LOSS)	(2,066)	(8,397)	277
OTHER INCOME (EXPENSE):			
Investment income (loss)	94	67	(14)
Miscellaneous income	7	7	3
Interest expense — affiliates	(19)	(7)	(7)
Interest expense — other	(138)	(147)	(147)
Capitalized interest	26	34	35
Total other expense	(30)	(46)	(130)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(2,096)	(8,443)	147
INCOME TAXES (BENEFITS)	295	(2,988)	65
NET INCOME (LOSS)	$(2,391)	$(5,455)	$82
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)			
NET INCOME (LOSS)	$(2,391)	$(5,455)	$82
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(14)	(14)	(6)
Amortized gains on derivative hedges	2	—	(3)
Change in unrealized gain on available-for-sale securities	30	52	(9)

Other comprehensive income (loss)	18	38	(18)
Income taxes (benefits) on other comprehensive income (loss)	6	15	(7)
Other comprehensive income (loss), net of tax	12	23	(11)
COMPREHENSIVE INCOME (LOSS)	$(2,379)	$(5,432)	$71

* Includes excise tax collections of $20 million, $28 million and $44 million in 2017, 2016 and 2015, respectively.

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $2 in 2017 and $5 in 2016	181	213
Affiliated companies	224	452
Other	21	27
Notes receivable from affiliated companies	—	29
Materials and supplies	183	267
Derivatives	34	137
Collateral	130	157
Prepaid taxes and other	22	63
	796	1,347
PROPERTY, PLANT AND EQUIPMENT:		
In service	2,495	7,057
Less — Accumulated provision for depreciation	1,823	5,929
	672	1,128
Construction work in progress	22	427
	694	1,555
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,856	1,552
Other	9	10
	1,865	1,562
DEFERRED CHARGES AND OTHER ASSETS:		
Accumulated deferred income taxes	1,754	2,279
Property taxes	25	40
Derivatives	—	77
Other	380	381
	2,159	2,777
	$ 5,514	$ 7,241
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 524	$ 179
Short-term borrowings - affiliated companies	105	101
Accounts payable-		
Affiliated companies	255	550
Other	105	110
Accrued taxes	72	143
Derivatives	24	77
Other	169	156
	1,254	1,316
CAPITALIZATION:		
Common stockholder's equity (deficit) -		

Common stock, without par value, authorized 750 shares - 7 shares outstanding as of December 31, 2017 and 2016	3,749	3,658
Accumulated other comprehensive income	81	69
Accumulated deficit	(5,900)	(3,509)
Total common stockholder's equity (deficit)	(2,070)	218
Long-term debt and other long-term obligations	2,299	2,813
	229	3,031
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	723	757
Retirement benefits	153	197
Asset retirement obligations	1,945	901
Other	1,210	1,039
	4,031	2,894
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16)		
	$ 5,514	$ 7,241

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (DEFICIT)

(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, 2015	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 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)
Net loss				(2,391)
Amortized gain on derivative hedges, net of $1 million of income taxes			1	
Change in unrealized gain on investments, net of $10 of income taxes			20	
Pension and OPEB, net of $5 of income tax benefits (Note 4)			(9)	
Inter-company asset transfer (Note 14)		73		
Stock-based compensation		3		
Consolidated tax benefit allocation		18		
Reclass to liability awards (Note 5)		(3)		
Balance, December 31, 2017	7	$ 3,749	$ 81	$ (5,900)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31		
(In millions)	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$(2,391)	$(5,455)	$82
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	333	633	579
Investment impairments	13	19	90
Pension and OPEB mark-to-market adjustment	24	48	57
Deferred income taxes and investment tax credits, net	455	(2,920)	119
Deferred costs on sale and leaseback transaction, net	49	49	48
Impairment of assets and related charges (Note 2)	2,031	8,622	33
Pension trust contribution	—	(138)	—
Gain on investment securities held in trusts	(62)	(48)	(24)
Unrealized (gain) loss on derivative transactions (Note 11)	78	9	(74)
Lease payments on sale and leaseback transaction	(73)	(120)	(131)
Change in current assets and liabilities-			
Receivables	282	89	277
Materials and supplies	(24)	26	(25)
Prepaid taxes and other	43	(8)	14
Accounts payable	(167)	(30)	(76)
Accrued taxes	(71)	76	(26)
Other current liabilities	—	15	43
Cash collateral, net	27	(87)	159
Other	180	6	7
Net cash provided from operating activities	727	786	1,152
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	—	471	341
Short-term borrowings, net	4	101	—
Redemptions and repayments-			
Long-term debt	(163)	(507)	(411)
Short-term borrowings, net	—	—	(126)
Common stock dividend payments	—	—	(70)
Other	(7)	(9)	(7)
Net cash (used for) provided from financing activities	(166)	56	(273)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(275)	(546)	(627)
Nuclear fuel	(254)	(232)	(190)
Proceeds from asset sales	—	9	13
Sales of investment securities held in trusts	940	717	733
Purchases of investment securities held in trusts	(999)	(783)	(791)

Cash investments	(3)	10	(10)
Loans to affiliated companies, net	29	(18)	(11)
Other	—	1	4
Net cash used for investing activities	(562)	(842)	(879)
Net change in cash and cash equivalents	(1)	—	—
Cash and cash equivalents at beginning of period	2	2	2
Cash and cash equivalents at end of period	$1	$2	$2
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$128	$111	$114
Income taxes received, net of payments	$(152)	$(193)	$(5)
Non-cash transaction: Affiliated net asset transfer (Note 14)	$73	$28	$—

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

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FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FE was incorporated under Ohio law 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, MAIT 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 over six million customers in the Midwest and Mid-Atlantic regions. Its regulated and unregulated generation subsidiaries control over 16,000 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 24,500 miles of lines and two regional transmission operation centers.
FES, a subsidiary of FE, was incorporated under Ohio law 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, which are operated by FENOC. 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 terminated the PSA effective on April 1, 2017. FES complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NRC and applicable state regulatory authorities.

FE and its subsidiaries follow GAAP and comply with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the NRC, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not necessarily indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation as appropriate. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 9, "Variable Interest Entities"). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but do not have a controlling financial interest, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage of FE's ownership share of the entity’s earnings is reported in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). These Notes to Consolidated Financial Statements are combined for FirstEnergy and FES.

Certain prior year amounts have been reclassified to conform to the current year presentation, including the reclassification of $30 million and $105 million of deferred purchased power and fuel costs previously included in

Purchased power to Amortization of regulatory assets, net, for the years ended December 31, 2016 and 2015, respectively.

Strategic Review of Competitive Operations

FirstEnergy's strategy is to be a fully regulated utility company, focusing on stable and predictable earnings and cash flow from its regulated business units - Regulated Distribution and Regulated Transmission. The Company continues to focus on its regulated growth strategy and in November 2016, FirstEnergy announced a strategic review to exit its commodity-exposed generation at CES, which is primarily comprised of the operations of FES and AE Supply.

In connection with this strategic review, AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments and through multiple, independent closings. On December 13, 2017, AE Supply completed the sale of the natural gas generating plants with net proceeds, subject to post-closing adjustments, of approximately $388 million. The sale of AE Supply's interests in the Bath County hydroelectric power station and the Buchanan Generating facility is expected to generate net proceeds of $375 million and is anticipated to close in the first half of 2018, subject in each case to various customary and other closing conditions, including, without limitation, receipt of regulatory approvals.

Additionally, on March 6, 2017, AE Supply and MP entered into an asset purchase agreement for MP to acquire AE Supply's Pleasants Power Station (1,300 MWs) for approximately $195 million, resulting from an RFP issued by MP to address its generation shortfall. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC’s affiliate cross-subsidization analysis. On January 26, 2018, the WVPSC approved the transfer of the Pleasants Power Station, subject to certain conditions as further described in Note 15, "Regulatory Matters - West Virginia," below, which included MP assuming significant commodity risk. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement and on February 16, 2018, AE Supply announced its intent to exit operations of the Pleasants Power Station by January 1, 2019, through either sale or deactivation, which resulted in a pre-tax impairment charge of $120 million.

With the sale of the gas plants completed, upon the consummation of the sale of AGC's interest in the Bath County hydroelectric power station or the sale or deactivation of the Pleasants Power Station, AE Supply is obligated under the amended and restated purchase agreement and AE Supply's applicable debt agreements to satisfy and discharge approximately $305 million of currently outstanding senior notes, as well as its $142 million of pollution control notes and AGC's $100 million senior notes, which are expected to require the payment of “make-whole” premiums currently estimated to be approximately $95 million based on current interest rates. For additional information see Note 2, "Asset Sales and Impairments."

The strategic options to exit the remaining portion of the CES portfolio, which is primarily at FES, are limited. The credit quality of FES, including its unsecured debt rating of Ca at Moody’s, C at S&P, and C at Fitch and the negative outlook from Moody’s and S&P, has challenged its ability to consummate asset sales. Furthermore, the inability to obtain legislative support under the Department of Energy’s recent NOPR, which was rejected by FERC, limits FES’ strategic options to plant deactivations, restructuring its debt and other financial obligations with its creditors, and/or to seek protection under U.S. bankruptcy laws.

As part of the strategic review, FES evaluated its options with respect to its nuclear power plants. Factors considered as part of this review included current and forecasted market conditions, such as wholesale power and capacity prices, legislative and regulatory solutions that recognize their environmental and energy security benefits, and many other factors, including the significant capital and operating costs associated with operating a safe and reliable nuclear fleet. Based on this analysis, given the weak power and capacity price environment and the lack of legislative and regulatory solutions achieved to date, FES concluded that it would be increasingly difficult to operate these facilities in this environment and absent significant change concluded that it was probable that the facilities would be either deactivated or sold before the end of their estimated useful lives. As a result, FES recorded a pre-tax charge of $2.0 billion in the fourth quarter of 2017 to fully impair the nuclear facilities, including the generating plants and nuclear fuel as well as to reserve against the value of materials and supplies inventory and to increase its asset retirement obligation. For additional information see Note 2, "Asset Sales and Impairments."

Going Concern at FES

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of January 31, 2018, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. As previously disclosed, FES has $515 million of maturing debt in 2018 (excluding intra-company debt), beginning with a $100 million principal payment due April 2, 2018. Based on FES' current senior unsecured debt rating, capital structure and long-term cash flow projections, the debt maturities are unlikely to be refinanced. Although management continues to explore cost reductions and other options to improve cash flow, these 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.

ACCOUNTING FOR THE EFFECTS OF REGULATION

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

FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income (Loss) concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

As a result of the Tax Act, FirstEnergy adjusted its net deferred tax liabilities at December 31, 2017, for the reduction in the corporate income tax rate from 35% to 21%. For the portions of FirstEnergy’s business that apply regulatory accounting, the impact of reducing the net deferred tax liabilities was offset with a regulatory liability, as appropriate, for amounts expected to be refunded to rate payers in future rates, with the remainder recorded to deferred income tax expense.

The following table provides information about the composition of net regulatory assets and liabilities as of December 31, 2017 and December 31, 2016, and the changes during the year ended December 31, 2017:

Net Regulatory Assets (Liabilities) by Source	December 31, 2017	December 31, 2016	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$46	$ 90	$ (44)
Customer receivables (payables) for future income taxes	(2,765)	468	(3,233)
Nuclear decommissioning and spent fuel disposal costs	(323)	(304)	(19)
Asset removal costs	(774)	(770)	(4)
Deferred transmission costs	187	122	65
Deferred generation costs	198	331	(133)
Deferred distribution costs	258	296	(38)
Contract valuations	118	153	(35)
Storm-related costs	329	397	(68)
Other	46	74	(28)
Net Regulatory Assets (Liabilities) included on the Consolidated Balance Sheets	$(2,680)	$ 857	$ (3,537)

Regulatory assets that do not earn a current return totaled approximately $7 million and $153 million as of December 31, 2017 and 2016, respectively, primarily related to storm damage costs, and are currently being recovered through rates.

REVENUES AND RECEIVABLES

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, FirstEnergy accrues the estimated unbilled amount as revenue and reverses the related prior period estimate.

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES. There was no material concentration of receivables as of December 31, 2017 and 2016 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2017 and 2016 are included below.

Customer Receivables	FirstEnergy	FES
	(In millions)	
December 31, 2017		
Billed	$860	$106
Unbilled	603	75
Total	$1,463	$181
December 31, 2016		
Billed	$833	$123
Unbilled	607	90
Total	$1,440	$213

EARNINGS (LOSS) PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. As discussed below in "New Accounting Pronouncements," FirstEnergy adopted ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting," beginning January 1, 2017. For the year ended December 31, 2017, there were no material impacts to the basic or diluted earnings per share due to the new standard.

Reconciliation of Basic and Diluted Earnings (Loss) per Share of Common Stock	2017	2016	2015
	(In millions, except per share amounts)		
Net income (loss)	$(1,724)	$(6,177)	$578
Weighted average number of basic shares outstanding	444	426	422
Assumed exercise of dilutive stock options and awards[1]	—	—	2
Weighted average number of diluted shares outstanding	444	426	424
Basic earnings (loss) per share of common stock	$(3.88)	$(14.49)	$1.37
Diluted earnings (loss) per share of common stock	$(3.88)	$(14.49)	$1.37

(1) For the years ended December 31, 2017, 2016 and 2015, approximately three million, three million and one million shares were excluded from the calculation of diluted shares outstanding, respectively, as their inclusion would be antidilutive, and in the case of 2016 and 2017, a result of the net loss for the period.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. The cost of nuclear fuel is capitalized within the CES segment's Property, plant and equipment and charged to fuel expense using the specific identification method. Property, plant and equipment balances by segment as of December 31, 2017 and 2016 were as follows:

	December 31, 2017				
Property, Plant and Equipment	In Service[1]	Accum. Depr.	Net Plant	CWIP	Total PP&E
	(In millions)				
Regulated Distribution	$25,950	$(7,503)	$18,447	$469	$18,916
Regulated Transmission	10,102	(2,055)	8,047	480	8,527
Competitive Energy Services[2]	2,902	(1,958)	944	28	972
Corporate/Other	824	(409)	415	49	464
Total	$39,778	$(11,925)	$27,853	$1,026	$28,879

	December 31, 2016				
Property, Plant and Equipment	In Service[1]	Accum. Depr.	Net Plant	CWIP	Total PP&E
	(In millions)				
Regulated Distribution	$24,979	$(7,169)	$17,810	$472	$18,282
Regulated Transmission	9,342	(1,948)	7,394	383	7,777
Competitive Energy Services[2]	8,680	(6,267)	2,413	453	2,866
Corporate/Other	766	(347)	419	43	462
Total	$43,767	$(15,731)	$28,036	$1,351	$29,387

(1) Includes capital leases of $238 million and $244 million at December 31, 2017 and 2016, respectively.
(2) Primarily consists of generating assets and nuclear fuel as discussed above. In 2017, FirstEnergy fully impaired the value of its nuclear generating assets and nuclear fuel.

The major classes of Property, plant and equipment are largely consistent with the segment disclosures above, with the exception of Regulated Distribution, which has approximately $2.1 billion of regulated generation property, plant and equipment.

Property, plant and equipment balances for FES as of December 31, 2017 and 2016 were as follows:

	December 31, 2017				
Property, Plant and Equipment	In Service	Accum. Depr.	Net Plant	CWIP	Total PP&E
	(In millions)				
Fossil Generation	$2,344	$(1,743)	$601	$ 19	$ 620
Other	151	(80)	71	3	74
Total	$2,495	$(1,823)	$672	$ 22	$ 694

	December 31, 2016				
Property, Plant and Equipment	In Service	Accum. Depr.	Net Plant	CWIP	Total PP&E
	(In millions)				
Fossil Generation	$2,212	$(1,720)	$492	$ 63	$555
Nuclear Generation	2,065	(1,723)	342	118	460
Nuclear Fuel	2,637	(2,418)	219	241	460
Other	143	(68)	75	5	80
Total	$7,057	$(5,929)	$1,128	$ 427	$1,555

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's and FES' electric plant in 2017, 2016 and 2015 are shown in the following table:

	Annual Composite Depreciation Rate		
	2017	2016	2015
FirstEnergy	2.4%	2.5%	2.5%
FES	4.4%	3.3%	3.2%

During the third quarter of 2016, FirstEnergy recorded a reduction to depreciation expense of $21 million ($19 million prior to January 1, 2016) that related to prior periods. The out-of-period adjustment related to the utilization of an accelerated useful life for a component of a certain power station. Management determined this adjustment was not material to 2016 or any prior periods.

For the years ended December 31, 2017, 2016 and 2015, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $35 million, $37 million and $49 million, respectively, of allowance for equity funds used during construction and $44 million, $66 million and $68 million, respectively, of capitalized interest.

For the years ended December 31, 2017, 2016 and 2015, capitalized financing costs on FES' Consolidated Statements of Income (Loss) includes $26 million, $34 million and $35 million, respectively, of capitalized interest.

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,003 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, VEPCO, a non-affiliated utility. Net Property, plant and equipment includes $531 million representing AGC's share in this facility as of December 31, 2017 of which $365 million is unregulated and included within the CES segment. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statements of Income (Loss). Approximately 59% of AGC is owned by AE Supply and approximately 41% by MP. As part of FE's strategic review of its competitive operations, on January 18, 2017, AGC entered into an asset purchase agreement (which was subsequently amended and restated) with a subsidiary of LS Power to sell AE Supply's indirect interest (23.75%) in Bath County, as discussed in Note 2, "Asset Sales and Impairments."

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, considering the expected timing of settlement of the ARO based on the expected economic useful life of the plants (including the likelihood that the facilities will be deactivated before the end of their estimated useful lives). 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, 2017, are described further in Note 14, "Asset Retirement Obligations."

Asset Impairments

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 2, "Asset Sales and Impairments," for long-lived asset impairments recognized in 2017 and 2016.

GOODWILL

In a business combination, the excess of the purchase price over the estimated fair value of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, and CES. The following table presents goodwill by reporting unit for the year ended December 31, 2017:

Goodwill	Regulated Distribution	Regulated Transmission	Consolidated
	(In millions)		
Balance as of December 31, 2017	$5,004	$ 614	$ 5,618

FirstEnergy tests goodwill for impairment annually as of July 31 and considers more frequent testing if indicators of potential impairment arise.

As of July 31, 2017, 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. Key factors used in the assessment include: growth rates, interest rates, expected capital expenditures, utility sector market performance and other market considerations. It was determined that the fair values 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 Sales and Impairments," for goodwill impairment recognized in 2016 at CES.

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and AFS securities.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset against regulatory assets or liabilities. In 2017, 2016 and 2015, FirstEnergy recognized $13 million, $21 million and $102 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $13 million, $19 million and $90 million, respectively. The fair values of FirstEnergy’s investments are disclosed in Note 10, "Fair Value Measurements."

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

FirstEnergy holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. In 2015, Global Holding incurred losses primarily as a result of declines in coal prices due to weakening global and U.S. coal demand. Based on the significant decline in coal pricing and the outlook for the coal market, including the significant decline in the market capitalization of coal companies in 2015, FirstEnergy assessed the value of its investment in Global Holding and determined there was a decline in the fair value of the investment below its carrying value that was other than temporary, resulting in a pre-tax impairment charge of $362 million recognized in 2015. Key assumptions incorporated into the discounted cash flow analysis utilized in the impairment analysis included the discount rate, future long-term coal prices, production levels, sales forecasts, projected capital and operating costs. The impairment charge is classified as a component of Other Income (Expense) in the Consolidated Statement of Income (Loss). See Note 9, "Variable Interest Entities," for further discussion of FirstEnergy's investment in Global Holding.

INVENTORY

Materials and supplies inventory includes fuel inventory and the distribution, transmission and generation plant materials, net of reserve for excess and obsolete inventory. Materials are generally charged to inventory at weighted average cost when purchased and expensed or capitalized, as appropriate, when used or installed. Fuel inventory is accounted for at weighted average cost when purchased, and recorded to fuel expense when consumed.

See Note 2, "Asset Sales and Impairments," for inventory-related charges recognized in 2017.

NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Pronouncements

ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting" (Issued March 2016): ASU 2016-09 simplifies several aspects of the accounting for employee share-based payments. The new guidance requires all income tax effects of awards to be recognized in the income statement when the awards vest or are settled. It also does not require liability accounting when an employer repurchases more of an employee’s shares for tax withholding purposes. FirstEnergy adopted ASU 2016-09 on January 1, 2017. Upon adoption, FirstEnergy elected to account for forfeitures as they occur. The change was applied on a modified retrospective basis with a cumulative effect adjustment to retained earnings of approximately $6 million as of January 1, 2017. Additionally, FirstEnergy retrospectively applied the cash flow presentation requirement to present cash paid to tax authorities when shares are withheld to satisfy statutory tax withholding obligations as financing activities by reclassifying $12 million and $13 million from operating activities to financing activities in the 2016 and 2015 Consolidated Statements of Cash Flows, respectively.

ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments" (Issued August 2016): The standard is intended to eliminate diversity in practice in how certain cash receipts and cash payments are presented and classified in the Consolidated Statements of Cash Flows, including the presentation of debt prepayment or debt extinguishment costs, all of which will be classified as financing activities. ASU 2016-15 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. FirstEnergy early adopted this ASU as of January 1, 2017. There was no impact to prior periods.

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB was not adopted in 2017. Unless otherwise indicated, FirstEnergy is currently assessing the impact such guidance may have on its financial statements and disclosures, as well as the potential to early adopt where applicable. FirstEnergy has assessed other FASB issuances of new standards not described below and has not included these standards based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting.

ASU 2014-09, "Revenue from Contracts with Customers" (Issued May 2014 and subsequently updated to address implementation questions): The new revenue recognition guidance: establishes a new control-based revenue recognition model, changes the basis for deciding when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific topics and expands and improves disclosures about revenue. FirstEnergy has evaluated its revenues and the new guidance will have limited impacts to current revenue recognition practices upon adoption on January 1, 2018. As part of the adoption, FirstEnergy elected to apply the new guidance on a modified retrospective basis. FirstEnergy will not record a cumulative adjustment to retained earnings for initially applying the new guidance as no revenue recognition differences were identified in the timing or amount of revenue. In addition, upon adoption, certain immaterial financial statement presentation changes will be implemented. FirstEnergy expects to disaggregate revenue by type of service in future revenue disclosures.

ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities" (issued January 2016): ASU 2016-01 primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. Upon adoption, January 1, 2018, FirstEnergy will recognize all gains and losses for equity securities in income with the exception of those that are accounted for under the equity method of accounting. The NDT's equity portfolios of JCP&L, ME and PN will not be impacted as unrealized gains and losses will continue to be offset against regulatory assets or liabilities. As a result of adopting the standard, FirstEnergy and FES will record a cumulative effect adjustment to retained earnings of $115 million (pre-tax) on January 1, 2018 representing unrealized gains on equity securities that were previously recorded to AOCI.

ASU 2016-02, "Leases (Topic 842)" (Issued February 2016) and ASU 2018-01,"Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842" (Issued January 2018): ASU 2016-02 will require organizations that lease assets with lease terms of more than 12 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. ASU 2018-01 (same effective date and transition requirements as ASU 2016-02) provides an optional transition practical expedient that, if elected, would not require an entity to reconsider its accounting for existing land easements that are not currently accounted for under the old leases standard. FirstEnergy does not plan to adopt these standards early. 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 expects an increase in assets and liabilities, however, it is currently assessing the impact on its Consolidated Financial Statements. This assessment includes monitoring utility industry implementation guidance. FirstEnergy is in the process of conducting outreach activities across its business units and analyzing its lease population. In addition, it has begun implementation of a third-party software tool that will assist with the initial adoption and ongoing compliance.

ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" (issued June 2016): ASU 2016-13 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.

ASU 2016-16, "Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory" (issued October 2016): 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 will not be impacted upon its adoption of this ASU on January 1, 2018.

ASU 2016-18, "Restricted Cash" (issued November 2016): ASU 2016-18 addresses the presentation of changes in restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is required to be applied retrospectively. In its first quarter 2018 Form 10-Q, FirstEnergy will show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. In addition, FirstEnergy will disclose the nature of its restricted cash and restricted cash equivalent balances within the footnotes.

ASU 2017-01, "Business Combinations: Clarifying the Definition of a Business" (Issued January 2017): ASU 2017-01 assists entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. The ASU will be applied prospectively to any transactions occurring within the period of adoption. FirstEnergy will not early adopt this standard.

ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (Issued March 2017): ASU 2017-07 requires entities to retrospectively (1) disaggregate the current-service-cost component from the other components of net benefit cost (the “other components”) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. As a result of the retrospective presentation, FirstEnergy will reclassify approximately $62 million of non-service costs, excluding the annual mark-to-market, to Other Income/Expense related to the fiscal year 2017 within the 2018 financial statements. In addition, ASU 2017-07 requires service costs to be capitalized as appropriate and non-service costs to be charged to earnings. FirstEnergy will present non-service costs in the caption “Miscellaneous Income” with the exception of the annual mark-to-market adjustment which will be disclosed separately.

ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" (Issued February 2018): ASU 2018-02 allows entities to reclassify from AOCI to retained earnings stranded tax effects resulting from the Tax Act. ASU 2018-02 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2018. Early adoption of the ASU is permitted including adoption in any interim period. ASU 2018-02 should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the income tax rate change resulting from the Tax Act is recognized. FirstEnergy did not adopt this ASU as of December 31, 2017.

2. ASSET SALES AND IMPAIRMENTS

YEAR ENDED DECEMBER 31, 2017

Early Retirement of Nuclear Generating Assets

As previously disclosed, FirstEnergy announced a strategic review to exit commodity-exposed generation at CES, which included one or more of the following options:

- legislative or regulatory solutions for generation assets that recognize their environmental or energy security benefits,
- restructuring FES' debt with its creditors,
- seeking protection under U.S. bankruptcy laws for FES and likely FENOC, and/or
- asset sales and/or plant deactivations.

As part of the strategic review, FES evaluated its options with respect to its nuclear power plants. Factors considered as part of this review included current and forecasted market conditions, such as wholesale power and capacity prices, legislative and regulatory solutions that recognize their environmental and energy security benefits, and many other factors, including the significant capital and operating costs associated with operating a safe and reliable nuclear fleet. Based on this analysis, given the weak power and capacity price environment and the lack of legislative and regulatory solutions achieved to date, FES concluded that it would be increasingly difficult to operate these facilities in this environment and absent significant change concluded that it was probable that the facilities would be either deactivated or sold before the end of their estimated useful lives. As a result, FES recorded a pre-tax charge of $2.0 billion in the fourth quarter of 2017 to fully impair the nuclear facilities, including the generating plants and nuclear fuel as well as to reserve against the value of materials and supplies inventory and to increase its asset retirement obligation. The charges consisted of the following:

(In millions)	Pre-tax charge
Nuclear generating asset	
Beaver Valley	$107
Davis Besse	420
Perry	124
Nuclear fuel	369
Materials and supplies	81
Asset retirement obligation	944
Total non-cash charges	$2,045

The fair value analysis for the generating assets was based on the income approach, a discounted cash flow method, to determine the amount of the impairment. Key assumptions used in determining the pre-tax non-cash charge included forward power and capacity price projections, the expected economic useful life of the plants (including the likelihood that the facilities will be deactivated before the end of their estimated useful lives), the timing of decommissioning activities, and operating and capital costs, all of which are subject to a high degree of judgment and complexity.

In addition to these one-time non-cash impairment charges, there will be ongoing charges to earnings primarily related to ongoing capital and nuclear fuel spend, as well as additional ARO accretion expense.

Pleasants Power Station

On March 6, 2017, AE Supply and MP entered into an asset purchase agreement for MP to acquire AE Supply's Pleasants Power Station (1,300 MWs) for approximately $195 million, resulting from an RFP issued by MP to address its generation shortfall. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC's affiliate cross-subsidization analysis. On January 26, 2018, the WVPSC approved the transfer of Pleasants, subject to certain conditions as further described below, which included MP assuming significant commodity risk. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement and on February 16, 2018, AE Supply announced its intent to exit operations of the Pleasants Power Station by January 1, 2019, through either sale or deactivation, which resulted in a pre-tax impairment charge of $120 million in the fourth quarter of 2017 to reduce the carrying value to $75 million.

Competitive Generation Asset Sale

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments and through multiple, independent closings. On December 13, 2017, AE Supply completed the sale of the natural gas generating plants with net proceeds, subject to post-closing adjustments, of approximately $388 million. The sale of AE Supply's interests in the Bath County hydroelectric power station and the Buchanan Generating facility is expected to generate net proceeds of $375 million and is anticipated to close in the first half of 2018, subject in each case to various customary and other closing conditions, including, without limitation, receipt of regulatory approvals.

As part of the closing of the natural gas generating plants, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement.

With the sale of the gas plants completed, upon the consummation of the sale of AGC's interest in the Bath County hydroelectric power station or the sale or deactivation of the Pleasants Power Station, AE Supply is obligated under the amended and restated purchase agreement and AE Supply's applicable debt agreements to satisfy and discharge approximately $305 million of currently outstanding senior notes, as well as its $142 million of pollution control notes and AGC's $100 million senior notes, which are expected to require the payment of "make-whole" premiums currently estimated to be approximately $95 million based on current interest rates.

On October 20, 2017, the parties filed an application with the VSCC for approval of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station. On December 12, 2017, FERC issued an order authorizing the partial transfer of the related hydroelectric license for Bath County under Part I of the FPA. In December 2017, AGC, AE Supply and MP filed with FERC and AGC and AE Supply filed with the VSCC, applications for approval of AGC redeeming AE Supply’s shares in AGC upon consummation of the Bath County transaction. On February 2, 2018, the VSCC issued an order finding that approval of the proposed stock redemption is not required, and on February 16, 2018, FERC issued an order authorizing the redemption. Upon the consummation of the redemption, AGC will become a wholly-owned subsidiary of MP.

On December 28, 2017, FERC issued an order authorizing the sale of BU Energy’s Buchanan interests. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once the sales are consummated. There can be no assurance that all regulatory approvals will be obtained and/or all closing conditions will be satisfied or that the remaining transactions will be consummated.

As a result of the amended asset purchase agreement, CES recorded non-cash pre-tax impairment charges of $193 million in 2017, reflecting the $825 million purchase price as well as certain purchase price adjustments based on timing of the closing of the transaction.

Assets held for sale related to this transaction as of December 31, 2017, include property, plant and equipment (net of accumulated provision for depreciation) of $354 million, investments of $19 million, and materials and supplies inventory of $2 million.

Transmission Formula Rate Settlements

As described in Note 15, "Regulatory Matters," on October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC, which is subject to a final order. As a result of the settlement agreement, MAIT recorded a pre-tax impairment charge of $13 million in the third quarter of 2017.

As described in Note 15, "Regulatory Matters," on December 21, 2017, JCP&L and certain parties filed a settlement agreement with FERC, which is subject to a final order. As a result of the settlement agreement, JCP&L recorded a pre-tax impairment charge of $28 million in the fourth quarter of 2017.

YEAR ENDED DECEMBER 31, 2016

Competitive Generation Deactivations and Other Exit Activities

On July 22, 2016, FirstEnergy and FES announced its intent to exit operations of the Bay Shore Unit 1 generating station (136 MWs) by October 1, 2020, through either sale or deactivation and to deactivate Units 1-4 of the W. H. Sammis generating station (720 MWs) by May 31, 2020. As a result, FirstEnergy recorded a non-cash pre-tax impairment charge of $647 million ($517 million - FES) in the second quarter of 2016. PJM and the Independent Market Monitor have approved the W.H. Sammis Units 1-4 and Bay Shore Unit 1 deactivations. In addition, FirstEnergy and FES recorded termination and settlement costs on fuel contracts of approximately $58 million (pre-tax) in the second quarter of 2016 resulting from plant retirements and deactivations, which is included in the caption of Fuel in the Consolidated Statement of Income (Loss).

As disclosed in Note 1, "Organization and Basis of Presentation," in November 2016, FirstEnergy announced a strategic review to exit its commodity-exposed generation as it transitions to a fully regulated utility.

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 the 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.

Key assumptions used in determining the impairment charges of long-lived assets included forward power price projections, the expected duration of ownership of the plants, environmental compliance costs and strategies, operating costs, and estimated sale proceeds. Those same cash flow assumptions, along with a discount rate were used to estimate the fair value of each plant. These assumptions are subject to a high degree of judgment and complexity. The fair value estimate of these long-lived assets was based on a combination of the income approach, which considers discounted cash flows, and corroboration with the market approach, which considers market comparisons for similar assets within the electric generation industry.

Goodwill

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, FirstEnergy determined that an interim impairment analysis of the CES reporting unit’s goodwill was necessary during the second quarter of 2016.

Consistent with FirstEnergy’s annual goodwill impairment test, a discounted cash flow analysis was used to determine the fair value of the CES reporting unit for purposes of step one of the interim goodwill impairment test. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- Future Energy and Capacity Prices: Observable market information for near-term forward power prices, PJM auction results for near term capacity pricing, and a longer-term fundamental pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- Retail Sales and Margin: CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.
- Operating and Capital Costs: Estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- Discount Rate: A discount rate of 9.50%, based on selected comparable companies' capital structure, return on debt and return on equity.
- Terminal Value: A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the impairment analysis, FirstEnergy determined that the carrying value of goodwill exceeded its fair value and recognized a non-cash pre-tax impairment charge of $800 million ($23 million - FES) in the second quarter of 2016, which is included in Impairment of assets and related charges in the Consolidated Statement of Income (Loss).

YEAR ENDED DECEMBER 31, 2015

During 2015, FirstEnergy and FES recognized impairment charges of $42 million and $33 million, respectively, associated with certain transportation equipment and facilities. In order to conform to current year presentation, the charges were reclassified from Other operating expenses in the Consolidated Statement of Income (Loss) to Impairment of assets and related charges. The impairment charges are included within the Regulated Distribution segment ($8 million) and the CES segment ($34 million).

3. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the years ended December 31, 2017, 2016 and 2015 for FirstEnergy are shown in the following table:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance, January 1, 2015	$(37)	$ 25	$ 258	$246
Other comprehensive income before reclassifications	—	14	10	24
Amounts reclassified from AOCI	5	(25)	(126)	(146)
Other comprehensive income (loss)	5	(11)	(116)	(122)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(44)	(47)
Other comprehensive income (loss), net of tax	4	(7)	(72)	(75)
AOCI Balance, December 31, 2015	$(33)	$ 18	$ 186	$171
Other comprehensive income before reclassifications	—	106	13	119
Amounts reclassified from AOCI	8	(51)	(72)	(115)
Other comprehensive income (loss)	8	55	(59)	4
Income tax (benefits) on other comprehensive income (loss)	3	21	(23)	1
Other comprehensive income (loss), net of tax	5	34	(36)	3
AOCI Balance, December 31, 2016	$(28)	$ 52	$ 150	$174
Other comprehensive income before reclassifications	—	85	(11)	74
Amounts reclassified from AOCI	10	(63)	(74)	(127)
Other comprehensive income (loss)	10	22	(85)	(53)
Income tax (benefits) on other comprehensive income (loss)	4	7	(32)	(21)
Other comprehensive income (loss), net of tax	6	15	(53)	(32)
AOCI Balance, December 31, 2017	$(22)	$ 67	$ 97	$142

The following amounts were reclassified from AOCI for FirstEnergy in the years ended December 31, 2017, 2016 and 2015:

FirstEnergy	Year Ended December 31			Affected Line Item in Consolidated Statements of Income (Loss)
Reclassifications from AOCI [2]	2017	2016	2015	
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$2	$—	$(3)	Other operating expenses
Long-term debt	8	8	8	Interest expense
	10	8	5	Total before taxes
	(4)	(3)	(1)	Income taxes (benefits)
	$6	$5	$4	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$(63)	$(51)	$(25)	Investment income (loss)
	23	19	9	Income taxes (benefits)
	$(40)	$(32)	$(16)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$(74)	$(72)	$(126)	[1]
	28	27	49	Income taxes (benefits)
	$(46)	$(45)	$(77)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 4, "Pension and Other Postemployment Benefits," for additional details.
[2] Parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

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The changes in AOCI for the years ended December 31, 2017, 2016 and 2015 for FES are shown in the following table:

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance, January 1, 2015	$(7)	$ 21	$ 43	$57
Other comprehensive income before reclassifications	—	15	10	25
Amounts reclassified from AOCI	(3)	(24)	(16)	(43)
Other comprehensive loss	(3)	(9)	(6)	(18)
Income tax benefits on other comprehensive loss	(1)	(4)	(2)	(7)
Other comprehensive loss, net of tax	(2)	(5)	(4)	(11)
AOCI Balance, December 31, 2015	$(9)	$ 16	$ 39	$46
Other comprehensive income before reclassifications	—	100	—	100
Amounts reclassified from AOCI	—	(48)	(14)	(62)
Other comprehensive income (loss)	—	52	(14)	38
Income tax (benefits) on other comprehensive income (loss)	—	20	(5)	15
Other comprehensive income (loss), net of tax	—	32	(9)	23
AOCI Balance, December 31, 2016	$(9)	$ 48	$ 30	$69
Other comprehensive income before reclassifications	—	91	—	91
Amounts reclassified from AOCI	2	(61)	(14)	(73)
Other comprehensive income (loss)	2	30	(14)	18
Income tax (benefits) on other comprehensive income (loss)	1	10	(5)	6
Other comprehensive income (loss), net of tax	1	20	(9)	12
AOCI Balance, December 31, 2017	$(8)	$ 68	$ 21	$81

The following amounts were reclassified from AOCI for FES in the years ended December 31, 2017, 2016 and 2015:

FES	Year Ended December 31			Affected Line Item in Consolidated Statements of Income (Loss)
Reclassifications from AOCI [2]	2017	2016	2015	
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$2	$—	$(3)	Other operating expenses
	(1)	—	1	Income taxes (benefits)
	$1	$—	$(2)	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$(61)	$(48)	$(24)	Investment income (loss)
	23	18	9	Income taxes (benefits)
	$(38)	$(30)	$(15)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$(14)	$(14)	$(16)	[1]
	5	5	6	Income taxes (benefits)
	$(9)	$(9)	$(10)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 4, "Pension and Other Postemployment Benefits," for additional details.
[2] Parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

4. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pension and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

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, 2017, 2016, and 2015 were $141 million, $147 million, and $242 million, respectively. In 2017, the pension and OPEB mark-to-market adjustment primarily reflects a 50 bps decrease in the discount rate used to measure benefit obligations, partially offset by higher than expected asset returns.

FirstEnergy’s pension and OPEB 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 2017 funding obligations 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 January 2018, FirstEnergy satisfied its minimum required funding obligations of $500 million and addressed funding obligations for future years to its qualified pension plan with additional contributions of $750 million.

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

FirstEnergy’s assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2017, FirstEnergy’s qualified pension and OPEB plan assets experienced gains of $999 million, or 15.1%, compared to gains of $472 million, or 8.2%, in 2016 and losses of $(172) million, or (2.7)%, in 2015, and assumed a 7.50% rate of return for 2017 and 2016 and a 7.75% rate of return for 2015 on plan assets which generated $478 million, $429 million and $476 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

During 2017, the Society of Actuaries released its updated mortality improvement scale for pension plans, MP-2017, incorporating three additional years of SSA data on U.S. population mortality. MP-2017 incorporates SSA mortality data from 2013 to 2015 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. Due to the additional years of data on population mortality, the RP2014 mortality table with the projection scale MP-2017 was utilized to determine the 2017 benefit cost and obligation as of December 31, 2017 for the FirstEnergy pension and OPEB plans. The impact of using the projection scale MP-2017 resulted in a decrease in the projected pension benefit obligation of $62 million and was included in the 2017 pension and OPEB mark-to-market adjustment.

Obligations and Funded Status - Qualified and Non-Qualified Plans	Pension 2017	Pension 2016	OPEB 2017	OPEB 2016
	(In millions)			
Change in benefit obligation:				
Benefit obligation as of January 1	$9,426	$9,079	$711	$724
Service cost	208	191	5	5
Interest cost	390	398	27	30
Plan participants' contributions	—	—	4	5
Plan amendments	11	—	—	(13)
Medicare retiree drug subsidy	—	—	1	1
Actuarial loss	610	224	32	14
Benefits paid	(478)	(466)	(49)	(55)
Benefit obligation as of December 31	$10,167	$9,426	$731	$711
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$6,213	$5,338	$420	$431
Actual return on plan assets	950	442	49	30
Company contributions	18	899	16	9
Plan participants' contributions	—	—	4	5
Benefits paid	(477)	(466)	(50)	(55)
Fair value of plan assets as of December 31	$6,704	$6,213	$439	$420
Funded Status:				
Qualified plan	$(3,043)	$(2,821)		
Non-qualified plans	(420)	(392)		
Funded Status	$(3,463)	$(3,213)	$(292)	$(291)
Accumulated benefit obligation	$9,583	$8,913	$—	$—
Amounts Recognized on the Balance Sheet:				
Noncurrent assets	$—	$9	$—	$—
Current liabilities	(19)	(19)	—	—
Noncurrent liabilities	(3,444)	(3,203)	(292)	(291)
Net liability as of December 31	$(3,463)	$(3,213)	$(292)	$(291)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$32	$28	$(206)	$(288)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	3.75 %	4.25 %	3.50 %	4.00 %
Rate of compensation increase	4.20 %	4.20 %	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	6.0-5.5%	6.0-5.5%
	N/A	N/A	4.5 %	4.5 %

Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)				
Year that the rate reaches the ultimate trend rate	N/A	N/A	2028	2027
Allocation of Plan Assets (as of December 31)				
Equity securities	42 %	44 %	50 %	53 %
Bonds	32 %	30 %	33 %	41 %
Absolute return strategies	10 %	8 %	— %	— %
Real estate funds	9 %	10 %	— %	— %
Private equity funds	1 %	— %	— %	— %
Cash and short-term securities	6 %	8 %	17 %	6 %
Total	100 %	100 %	100 %	100 %

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Components of Net Periodic Benefit Costs	Pension 2017	2016	2015	OPEB 2017	2016	2015
	(In millions)					
Service cost	$208	$191	$193	$5	$5	$5
Interest cost	390	398	383	27	30	29
Expected return on plan assets	(448)	(399)	(443)	(30)	(30)	(33)
Amortization of prior service cost (credit)	7	8	8	(81)	(80)	(134)
Pension & OPEB mark-to-market adjustment	108	179	344	13	15	25
Net periodic benefit cost (credit)	$265	$377	$485	$(66)	$(60)	$(108)

Assumptions Used to Determine Net Periodic Benefit Cost * for Years Ended December 31	Pension 2017	2016	2015	OPEB 2017	2016	2015
Weighted-average discount rate	4.25%	4.50%	4.25%	4.00%	4.25%	4.00%
Expected long-term return on plan assets	7.50%	7.50%	7.75%	7.50%	7.50%	7.75%
Rate of compensation increase	4.20%	4.20%	4.20%	N/A	N/A	N/A

*Excludes impact of pension and OPEB mark-to-market adjustment.

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

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 10, "Fair Value Measurements," for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2017 and 2016.

	December 31, 2017				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$—	$379	$—	$379	6 %
Equity investments					
Domestic	695	27	—	722	11 %
International	514	1,569	—	2,083	31 %
Fixed income					
Government bonds	—	251	—	251	4 %
Corporate bonds	—	1,237	—	1,237	18 %
High yield debt	—	689	—	689	10 %
Mortgage-backed securities (non-government)	—	31	—	31	— %
Alternatives					
Hedge funds (Absolute return)	—	635	—	635	10 %
Derivatives	—	(1)	—	(1)	— %
Real estate funds	—	—	631	631	9 %
Total (1)	$1,209	$4,817	$631	$6,657	99 %
Private equity funds (2)				57	1 %
Total Investments				$6,714	100 %

(1) Excludes $(10) million as of December 31, 2017, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

(2) Net asset value used as a practical expedient to approximate fair value.

	December 31, 2016				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$—	$464	$—	$464	8 %
Equity investments					
Domestic [(1)]	1,048	13	—	1,061	17 %
International	422	1,269	—	1,691	27 %
Fixed income					
Government bonds	—	106	—	106	2 %
Corporate bonds	—	1,245	—	1,245	20 %
High yield debt	—	372	—	372	6 %
Mortgage-backed securities (non-government)	—	112	—	112	2 %
Alternatives					
Hedge funds (Absolute return)	—	500	—	500	8 %
Derivatives	—	(1)	—	(1)	— %
Real estate funds	—	—	615	615	10 %
Total [(2)]	$1,470	$4,080	$615	$6,165	100 %
Private equity funds [(3)]				33	— %
Total Investments				$6,198	100 %

(1) As a result of the $500 million equity contribution on December 13, 2016, there was $293 million of FE Stock included in the pension plan assets as of December 31, 2016.

(2) Excludes $16 million as of December 31, 2016, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

(3) Net asset value used as a practical expedient to approximate fair value.

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2017 and 2016:

	Real Estate Funds
Balance as of January 1, 2016	$587
Actual return on plan assets:	
Unrealized gains	29
Realized gains (losses)	14
Transfers in	(15)
Balance as of December 31, 2016	$615
Actual return on plan assets:	
Unrealized gains	3
Realized gains	10
Transfers in (out)	3
Balance as of December 31, 2017	$631

As of December 31, 2017 and 2016, the OPEB trust investments measured at fair value were as follows:

	December 31, 2017				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$—	$75	$ —	$75	17 %
Equity investment					
Domestic	220	—	—	220	50 %
Fixed income					
Government bonds	—	109	—	109	24 %
Corporate bonds	—	34	—	34	8 %
Mortgage-backed securities (non-government)		3	—	3	1 %
Total [1]	$220	$221	$ —	$441	100 %

(1) Excludes $(2) million as of December 31, 2017, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2016				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$—	$27	$ —	$27	6 %
Equity investment					
Domestic	223	—	—	223	53 %
Fixed income					
U.S. treasuries	—	40	—	40	9 %
Government bonds	—	108	—	108	26 %
Corporate bonds	—	24	—	24	6 %
Mortgage-backed securities (non-government)	—	2	—	2	— %
Total [1]	$223	$201	$ —	$424	100 %

(1) Excludes $(4) million as of December 31, 2016, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

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

FirstEnergy’s target asset allocations for its pension and OPEB trust portfolios for 2017 and 2016 are shown in the following table:

Target Asset Allocations

Equities	38 %

Fixed income	30	%
Absolute return strategies	8	%
Real estate	10	%
Alternative investments	8	%
Cash	6	%
	100	%

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 1	$ (1)
Effect on accumulated benefit obligation	$ 21	$ (18)

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

	Pension	OPEB Benefit Payments	Subsidy Receipts
	(In millions)		
2018	$518	$55	$ (1)
2019	531	54	(1)
2020	552	53	(1)
2021	567	53	(1)
2022	581	52	(1)
Years 2023-2027	3,056	241	(3)

FES' share of the pension and OPEB net (liability) asset as of December 31, 2017 and 2016, was as follows:

	Pension		OPEB	
	2017	2016	2017	2016
	(In millions)			
Net (Liability) Asset[1]	$(97)	$(158)	$40	$ 36

[1] Excludes $954 million and $866 million as of December 31, 2017 and 2016, respectively, of affiliated non-current liabilities related to pension and OPEB mark-to-market costs allocated to FES of which $626 million and $570 million, respectively, are from FENOC.

FES' share of the net periodic benefit cost (credit), including the pension and OPEB mark-to-market adjustment, for the three years ended December 31, 2017, was as follows:

	Pension			OPEB		
	2017	2016	2015	2017	2016	2015
	(In millions)					
Net Periodic Cost (Credit)	$60	$(5)	$ 10	$(17)	$(26)	$(22)

5. STOCK-BASED COMPENSATION PLANS

FirstEnergy grants stock-based awards through the ICP 2015, primarily in the form of restricted stock and performance-based restricted stock units. Under FirstEnergy's previous incentive compensation plan, the ICP 2007, FirstEnergy also granted stock options and performance shares. The ICP 2007 and ICP 2015 include shareholder authorization to issue 29 million shares and 10 million shares, respectively, of common stock or their equivalent. As of December 31, 2017, approximately 6 million shares were available for future grants under the ICP 2015 assuming maximum performance metrics are achieved for the outstanding cycles of restricted stock units. No shares are available for future grants under the ICP 2007. Shares not issued due to forfeitures or cancellations may be added back to the ICP 2015. Shares used under the ICP 2007 and ICP 2015 are issued from authorized but unissued common stock. Vesting periods range from one to ten years, with the majority of awards having a vesting period of three years. FirstEnergy also issues stock through its 401(k) Savings Plan, EDCP, and DCPD. Currently, FirstEnergy records the compensation costs for stock-based compensation awards that will be paid in stock over the vesting period based on the fair value on the grant date. Beginning in 2017, based upon the adoption of ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting," FE has elected to account for forfeitures as they occur.

FirstEnergy adjusts the compensation costs for stock-based compensation awards that will be paid in cash based on changes in the fair value of the award as of each reporting date. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or settled. Actual income tax benefits realized during the years ended December 31, 2017, 2016 and 2015 were $15 million, $13 million and $10 million, respectively. The income tax effects of awards are recognized in the income statement when the awards vest or are settled.

Stock-based compensation costs and the amount of stock-based compensation expense capitalized related to FirstEnergy and FES plans are included in the following tables:

FirstEnergy	Years Ended December 31		
Stock-based Compensation Plan	2017	2016	2015
	(In millions)		
Restricted Stock Units	$49	$62	$ 46
Restricted Stock	1	2	2
Performance Shares	—	(3)	—
401(k) Savings Plan	42	39	38
EDCP & DCPD	6	5	3
Total	$98	$105	$ 89
Stock-based compensation costs capitalized	$37	$38	$ 32

FES	Years Ended December 31		
Stock-based Compensation Plan	2017	2016	2015
	(In millions)		
Restricted Stock Units	$4	$ 11	$ 6
401(k) Savings Plan	3	5	5
Total	$7	$ 16	$ 11
Stock-based compensation costs capitalized	$1	$ 2	$ 1

Outstanding stock options were fully amortized as of December 31, 2016. Stock option expense was not material for FirstEnergy or FES for the years December 31, 2016 and 2015. Income tax benefits associated with stock based compensation plan expense were $10 million, $14 million and $12 million (FES - $1 million, $2 million and $2 million) for the years ended 2017, 2016 and 2015, respectively.

Restricted Stock Units

Beginning with the performance-based restricted stock units granted in 2015, two-thirds will be paid in stock and one-third will be paid in cash. All performance-based restricted stock units granted prior to 2015 were payable in stock. Restricted stock units payable in stock provide the participant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement, subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets. The grant date fair value of the stock portion of the restricted stock unit award is measured based on the average of the high and low prices of FE common stock on the date of grant. Restricted stock units payable in cash provide the participant the right to receive cash based on the number of stock units set forth in the agreement and value of the equivalent number of shares of FE common stock as of the vesting date.

The cash portion of the restricted stock unit award is considered a liability award, which is remeasured each period based on FE's stock price and projected performance adjustments. The liability recorded for cash performance-based restricted stock units as of December 31, 2017 was $41 million. During 2017, restricted stock unit award agreements for certain employees were amended such that the two-thirds originally designated to be paid in stock will be paid in cash. These awards are included within the cash performance-based restricted stock unit liability. No cash was paid to settle the restricted stock unit obligations in 2017. The vesting period for each of the awards was three years. Dividend equivalents are received on the restricted stock units and are reinvested in additional restricted stock units and subject to the same performance conditions.

Restricted stock unit activity for the year ended December 31, 2017, was as follows:

Restricted Stock Unit Activity	Shares	Weighted-Average Grant Date Fair Value
Nonvested as of January 1, 2017	3,063,729	$ 32.98
Granted in 2017	1,577,844	31.71
Forfeited in 2017	(169,012)	32.66
Vested in 2017[1]	(1,156,810)	30.81
Nonvested as of December 31, 2017	3,315,751	$ 33.24

[1] Excludes dividend equivalents of 159,274 shares earned during vesting period.

The weighted-average fair value of awards granted in 2017, 2016 and 2015 was $31.71, $34.77 and $35.27, respectively. For the years ended December 31, 2017, 2016, and 2015, the fair value of restricted stock units vested was $42 million, $36 million, and $22 million, respectively. As of December 31, 2017, there was $33 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted for restricted stock units; that cost is expected to be recognized over a period of approximately three years.

Restricted Stock

Certain employees receive awards of FE restricted stock (as opposed to "units" with the right to receive shares at the end of the restriction period) subject to restrictions that lapse over a defined period of time or upon achieving performance results. The fair value of restricted stock is measured based on the average of the high and low prices of FirstEnergy common stock on the date of grant. Dividends are received on the restricted stock and are reinvested in additional shares of restricted stock. Restricted common stock (restricted stock) activity for the year ended December 31, 2017, was not material.

Stock Options

Stock options have been granted to certain employees allowing them to purchase a specified number of common shares at a fixed exercise price over a defined period of time. Stock options generally expire ten years from the date of grant. There were no stock options granted in 2017. Stock option activity during 2017 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2017 (1,376,821 options exercisable)	1,376,821	$ 44.60
Options forfeited	(9,946)	70.60
Balance, December 31, 2017 (1,366,875 options exercisable)	1,366,875	$ 44.41

There was no cash received from the exercise of stock options in 2017 and 2016. Cash received from the exercise of stock options in 2015 was not material. The weighted-average remaining contractual term of options outstanding as of December 31, 2017, was 1.67 years.

Performance Shares

Prior to the 2015 grant of performance-based restricted stock units discussed above, the Company granted performance shares. Performance shares are share equivalents and do not have voting rights. The performance shares outstanding track the performance of FE's common stock over a three-year vesting period. Dividend equivalents accrue on performance shares and are reinvested into additional performance shares with the same performance conditions. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. In 2016, $2 million cash was paid to settle performance shares that vested over the 2013-2015 performance cycle. In 2017, no cash was paid to settle performance shares that vested over the 2014-2016 performance cycle. FirstEnergy no longer has outstanding performance share awards.

401(k) Savings Plan

In 2017 and 2016, 1,304,863 and 1,159,215 shares of FE common stock, respectively, were issued and contributed to participants' accounts.

EDCP

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

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their equity retainers to deferred stock and their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $8 million and $7 million as of December 31, 2017 and December 31, 2016, respectively, is included in the caption “Retirement benefits,” on the Consolidated Balance Sheets.

6. 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.

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

On December 22, 2017, the President signed into law the Tax Act. Substantially all of the provisions of the Tax Act are effective for taxable years beginning after December 31, 2017. The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and includes specific provisions related to regulated public utilities including FirstEnergy’s regulated distribution and transmission subsidiaries. The more significant changes that impact FirstEnergy included in the Tax Act are the following:

- Reduction of the corporate federal income tax rate from 35% to 21%, effective in 2018;
- Full expensing of qualified property, excluding rate regulated utilities, through 2022 with a phase down beginning in 2023;
- Limitations on interest deductions with an exception for rate regulated utilities;

- Limitation of the utilization of federal NOLs arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward;
- Repeal of the corporate AMT and allowing taxpayers to claim a refund on any AMT credit carryovers.

The most significant change that impacts FirstEnergy in the current year is the reduction of the corporate federal income tax rate. Other provisions are not expected to have a significant impact on the financial statements, but may impact the effective tax rate in future years. Under US GAAP, specifically ASC Topic 740, Income Taxes, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted, or December 22, 2017, for the Tax Act. ASC 740 also requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Thus, at the date of enactment, FirstEnergy’s deferred taxes were re-measured based upon the new tax rate, which resulted in a material decrease to FirstEnergy’s net deferred income tax liabilities. For FirstEnergy’s unregulated operations, the change in deferred taxes are recorded as an adjustment to FirstEnergy’s deferred income tax provision. FirstEnergy’s regulated entities recorded a corresponding net regulatory liability to the extent the change in deferred taxes would result in amounts previously collected from utility customers to be subject to refunds to such customers, generally through reductions in future rates. All other amounts were recorded as an adjustment to FirstEnergy’s regulated entities’ deferred income tax provision.

FirstEnergy has completed its assessment of the accounting for certain effects of the provisions in the Tax Act, and as allowed under SEC Staff Accounting Bulletin 118 (SAB 118), has recorded provisional income tax amounts as of December 31, 2017 related to depreciation for which the impacts of the Tax Act could not be finalized, but for which a reasonable estimate could be determined.

Under the new law, property acquired and placed into service after September 27, 2017, will be eligible for full expensing for all taxpayers other than regulated utilities. As a result, FirstEnergy will need to evaluate the contractual terms of its capital expenditures to determine eligibility for full expensing. As of December 31, 2017, FirstEnergy has not yet completed this analysis, but has recorded a reasonable estimate of the effects of these changes based on capital costs incurred prior to year-end. In addition, SAB 118 allows for a measurement period for companies to finalize the provisional amounts recorded as of December 31, 2017. FirstEnergy expects to record any final adjustments to the provisional amounts by the fourth quarter of 2018, which could result in a material impact to FirstEnergy's income tax provision or financial position.

FirstEnergy's assessment of accounting for the Tax Act are based upon management's current understanding of the Tax Act. However, it is expected that further guidance will be issued during 2018, which may result in adjustments that could have a material impact to FirstEnergy's future results of operations, cash flows, or financial position.

As a result of the Tax Act, FirstEnergy recognized a non-cash charge to income tax expense of $1.2 billion (FES - $1.1 billion) and resulted in excess deferred taxes of $2.3 billion for the regulated business, of which the revenue impact was recorded as a regulatory liability. These adjustments had no impact on our 2017 cash flows.

INCOME TAXES (BENEFITS)	2017	2016	2015
	(In millions)		
FirstEnergy			
Currently payable (receivable)-			
Federal	$14	$(1)	$1
State	42	9	30
	56	8	31
Deferred, net-			
Federal	876	(3,114)	277
State	(29)	59	15
	847	(3,055)	292
Investment tax credit amortization	(8)	(8)	(8)
Total provision for income taxes (benefits)	$895	$(3,055)	$315
FES			
Currently payable (receivable)-			
Federal	$(159)	$(67)	$(56)
State	(1)	(1)	2
	(160)	(68)	(54)
Deferred, net-			
Federal	509	(2,861)	103
State	(52)	(57)	18
	457	(2,918)	121
Investment tax credit amortization	(2)	(2)	(2)
Total provision for income taxes (benefits)	$295	$(2,988)	$65

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

	2017	2016	2015
	(In millions)		
FirstEnergy			
Income (loss) before income taxes (benefits)	$(829)	$(9,232)	$893
Federal income tax expense (benefit) at statutory rate (35%)	$(290)	$(3,231)	$313
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	(4)	(192)	17
AFUDC equity and other flow-through	(15)	(13)	(16)
Amortization of investment tax credits	(8)	(8)	(8)
Change in accounting method	—	—	(8)
ESOP dividend	(6)	(6)	(6)
Impairment of non-deductible goodwill	—	157	—
Remeasurement of deferred taxes	1,193	—	—
Uncertain tax positions	(3)	(16)	1
Valuation allowances	29	246	18
Other, net	(1)	8	4
Total income taxes (benefits)	$895	$(3,055)	$315
Effective income tax rate	(108.0)%	33.1%	35.3%
FES			
Income (loss) before income taxes (benefits)	$(2,096)	$(8,443)	$147
Federal income tax expense (benefit) at statutory rate (35%)	$(734)	$(2,955)	$51
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	(52)	(188)	2
Amortization of investment tax credits	(2)	(2)	(2)
ESOP dividend	—	(1)	(1)
Impairment of non-deductible goodwill	—	9	—
Remeasurement of deferred taxes	1,067	—	—
Uncertain tax positions	—	(8)	5
Valuation allowances	18	151	14
Other, net	(2)	6	(4)
Total income taxes (benefits)	$295	$(2,988)	$65
Effective income tax rate	(14.1)%	35.4%	44.2%

Absent the impact from the Tax Act, discussed above, FirstEnergy's effective tax rate on pre-tax losses for 2017 and 2016 was 35.9% and 33.1%, respectively. The change in the effective tax rate resulted primarily from the absence of 2016 charges, including $246 million of valuation allowances recorded against state and local 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 was non-deductible for tax purposes.

Absent the impact from the Tax Act, discussed above, FES' 2017 effective tax rate on pre-tax losses for 2017 and 2016 was 36.8%, and 35.4%, respectively. The change in the effective tax resulted primarily from the absence of $151 million of valuation allowances recorded against state and local deferred tax assets, that management believes, more likely than not, will not be realized, as well as the impairment of $23 million of goodwill, which was non-deductible for tax purposes.

Accumulated deferred income taxes as of December 31, 2017 and 2016, are as follows:

	2017	2016
	(In millions)	
FirstEnergy		
Property basis differences	$3,662	$7,088
Deferred sale and leaseback gain	(231)	(351)
Pension and OPEB	(952)	(1,347)
Nuclear decommissioning activities	450	635
Asset retirement obligations	(453)	(669)
Regulatory asset/liability	416	545
Deferred compensation	(177)	(269)
Nuclear Fuel	(375)	(90)
Loss carryforwards and AMT credits	(1,467)	(2,251)
Valuation reserve	580	438
All other	(94)	36
Net deferred income tax liability	$1,359	$3,765
FES		
Property basis differences	$(677)	$(1,009)
Deferred sale and leaseback gain	(219)	(328)
Pension and OPEB	(244)	(366)
Lease market valuation liability	75	111
Nuclear decommissioning activities	411	540
Asset retirement obligations	(296)	(453)
Nuclear Fuel	(375)	(90)
Loss carryforwards and AMT credits	(587)	(830)
Valuation reserve	268	197
All other	(110)	(51)
Net deferred income tax asset	$(1,754)	$(2,279)

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state taxing authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2009-2016. In February 2017, the IRS completed its examination of FirstEnergy's 2015 federal income tax return and issued a Full Acceptance Letter with no changes or adjustments to FirstEnergy's taxable income. In August 2017, the IRS substantially completed its examination of FirstEnergy's 2016 federal income tax return and, on January 18, 2018, issued a Full Acceptance Letter with no changes or adjustments to FirstEnergy's taxable income.

FirstEnergy and FES have recorded as deferred income tax assets the effect of Federal NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2017, FirstEnergy's loss carryforwards and AMT credits consisted of $4.3 billion ($908 million, net of tax) of Federal NOL carryforwards that will begin to expire in 2031 and Federal AMT credits of $39 million that have an indefinite carryforward period. As of December 31, 2017, FES' loss carryforwards consisted of $2.0 billion ($429 million, net of tax) of Federal NOL carryforwards that will begin to expire in 2031.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $10.5 billion ($496 million, net of tax) for FirstEnergy, of which approximately $1.8 billion ($81 million, net of tax) is expected to be utilized based on current estimates and assumptions. FES' pre-tax NOL carryforwards for state and local income tax purposes is approximately $3.7 billion ($154 million, net of tax), of which $2 million is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

Expiration Period	FirstEnergy (In millions)		FES	
	State	Local	State	Local
2018-2022	$806	$3,472	$2	$1,954
2023-2027	1,963	—	32	—
2028-2032	2,382	—	703	—
2033-2037	1,896	—	982	—
	$7,047	$3,472	$1,719	$1,954

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. A recognition threshold and measurement attribute is utilized for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2017 and 2016, FirstEnergy's total unrecognized income tax benefits were approximately $80 million and $84 million, respectively. If ultimately recognized in future years, approximately $24 million of unrecognized income tax benefits would impact the effective tax rate.

On October 18, 2017, the Supreme Court of Pennsylvania affirmed the Commonwealth Court's holding that the state's net loss carryover provision violated the Pennsylvania Uniformity Clause and was unconstitutional. However, the supreme court also opined that the portion of the net loss carryover provision that created the violation may be severed from the statute, enabling the statute to operate as the legislature intended, and on October 30, 2017, the Pennsylvania Governor signed House Bill 542 into law which, among other things, amended Pennsylvania's limitation on net loss deductions to remove the flat-dollar limitation. On January 4, 2018, the supreme court denied to further hear any arguments related to the matter and, as a result, FirstEnergy withdrew its protective refund claims from the state of Pennsylvania on January 30, 2018. Upon doing so, FirstEnergy will reverse a previously recorded unrecognized tax benefit of approximately $45 million in the first quarter of 2018, none of which will impact FirstEnergy's effective tax rate.

As of December 31, 2017, it is reasonably possible that approximately $2 million of additional unrecognized tax benefits may be resolved during 2018 as a result of the statute of limitations expiring, none of which would affect FirstEnergy's effective tax rate.
The following table summarizes the changes in unrecognized tax positions for the years ended 2017, 2016 and 2015:

	FirstEnergy (In millions)	FES
Balance, January 1, 2015	$ 34	$ 3
Current year increases	3	—
Prior years increases	7	5
Prior years decreases	(10)	—
Balance, December 31, 2015	$ 34	$ 8
Current year increases	2	—
Prior years increases	69	—
Prior years decreases	(21)	(8)
Balance, December 31, 2016	$ 84	$ —
Current year increases	2	—
Decrease for lapse in statute	(6)	—
Balance, December 31, 2017	$ 80	$ —

FirstEnergy recognizes interest expense or income and penalties related to uncertain tax positions in income taxes. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy's recognition of net interest associated with unrecognized tax benefits in 2017, 2016, and 2015 was not material. For the years ended December 31, 2017 and 2016, the cumulative net interest payable recorded by FirstEnergy was not material.

General Taxes

General tax expense for 2017, 2016 and 2015, is summarized as follows:

	2017	2016	2015
	(In millions)		
FirstEnergy			
KWH excise	$188	$196	$193
State gross receipts	204	212	224
Real and personal property	486	472	410
Social security and unemployment	131	127	119
Other	34	35	32
Total general taxes	$1,043	$1,042	$978
FES			
State gross receipts	$20	$28	$44
Real and personal property	27	42	36
Social security and unemployment	11	15	16
Other	—	3	2
Total general taxes	$58	$88	$98

7. LEASES

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

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years, which expired in 2016 for Perry Unit 1 and in 2017 for Beaver Valley Unit 2. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and entered into similar operating leases for lease terms of approximately 30 years, which expired in 2017.

In 2007, FG completed a sale and leaseback transaction for its 93.83% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years, expiring in 2040. FES has unconditionally and irrevocably guaranteed all of FG’s obligations under each of the leases. As of December 31, 2017, 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 to100% of the unit's output.

On June 1, 2017, NG completed the purchase of the 2.60% lessor equity interests of the remaining non-affiliated leasehold interests in Beaver Valley Unit 2 for $38 million. In addition, the Beaver Valley Unit 2 leases expired in accordance with their terms on June 1, 2017, resulting in NG being the sole owner of Beaver Valley Unit 2.

Operating lease expense for 2017, 2016 and 2015, is summarized as follows:

(In millions)	2017	2016	2015
FirstEnergy	$158	$168	$174
FES	$93	$94	$94

The future minimum capital lease payments as of December 31, 2017 are as follows:

Capital Leases	FirstEnergy	FES
	(In millions)	
2018	$ 28	$ 2
2019	23	—
2020	18	—
2021	15	—
2022	13	—
Years thereafter	20	—
Total minimum lease payments	117	2
Interest portion	(26)	—
Present value of net minimum lease payments	91	2
Less current portion	24	2
Noncurrent portion	$ 67	$ —

The future minimum operating lease payments as of December 31, 2017, are as follows:

Operating Leases	FirstEnergy	FES
	(In millions)	

2018	$146	$101
2019	128	97
2020	102	68
2021	124	93
2022	111	91
Years thereafter	1,263	1,131
Total minimum lease payments	$1,874	$1,581

8. INTANGIBLE ASSETS

As of December 31, 2017, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, include the following:

	Intangible Assets			Amortization Expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2017	2018	2019	2020	2021	2022	Thereafter
NUG contracts[1]	$124	$ 36	$88	$5	$5	$ 5	$ 5	$ 5	$ 5	$ 63
OVEC	8	3	5	1	—	1	—	—	—	4
Coal contracts[2]	102	94	8	4	3	3	2	—	—	—
FES customer contracts	148	144	4	5	3	1	—	—	—	—
	$382	$ 277	$105	$15	$11	$ 10	$ 7	$ 5	$ 5	$ 67

(1) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.
(2) The coal contracts were recorded with a regulatory offset and their amortization does not impact earnings.

9. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses based on control and economics to determine whether a variable interest classifies FirstEnergy as the primary beneficiary (a controlling financial interest) of a VIE. An enterprise has a controlling financial interest if it has both power and economic control, such that an entity has (i) the power to direct the activities of a VIE that most significantly impact the entity's economic performance, and (ii) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

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

Consolidated VIEs

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

- Ohio Securitization - In September 2012, the Ohio Companies created separate, wholly-owned limited liability company SPEs which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. The SPEs are considered VIEs and each one is consolidated into its applicable utility. As of December 31, 2017 and December 31, 2016, $315 million and $339 million of the phase-in recovery bonds were outstanding, respectively.
- JCP&L Securitization - In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station, which were paid in full at maturity on June 5, 2017. Additionally, in August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding II

and are collateralized by its equity and assets, which consist primarily of bondable transition property. As of December 31, 2017 and December 31, 2016, $56 million and $85 million of the transition bonds were outstanding, respectively.

- MP and PE Environmental Funding Companies - The entities issued bonds, the proceeds of which were used to construct environmental control facilities. The limited liability company SPEs own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. Creditors of FirstEnergy, other than the limited liability company SPEs, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2017 and December 31, 2016, $383 million and $406 million of the environmental control bonds were outstanding, respectively.

FES does not have any consolidated VIEs.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- Global Holding - FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint venture's economic performance. FEV's ownership interest is subject to the equity method of accounting. In 2015, FirstEnergy fully impaired the value of its investment in Global Holding.

As discussed in Note 16, "Commitments, Guarantees and Contingencies," FE is the guarantor under Global Holding's term loan facility, which has an outstanding principal balance of $275 million. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

- PATH WV - PATH, a proposed transmission line from West Virginia through Virginia into Maryland which PJM cancelled in 2012, is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting. As of December 31, 2017, the carrying value of the equity method investment was $17 million.
- Purchase Power Agreements - FirstEnergy evaluated its PPAs and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant’s variable costs of production.

FirstEnergy maintains 12 long-term PPAs with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities. Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contract that may contain a variable interest were $112 million and $108 million, respectively, during the years ended December 31, 2017 and 2016.

- Sale and Leaseback Transactions - FES has obligations that are not included on its Consolidated Balance Sheet related to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement, which are satisfied through operating lease payments. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements.

FES is exposed to losses under the Bruce Mansfield Unit 1 sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses FirstEnergy's net exposure to loss based upon the casualty value provisions as of December 31, 2017:

Maximum Exposure	Discounted Lease Payments, net	Net Exposure
(In millions)		

FirstEnergy[1]	$1,083	$ 862	$ 221

[1] All amounts are associated with FES.

10. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs and NUGs follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term PJM auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent PJM auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 11, "Derivative Instruments," for additional information regarding FirstEnergy's FTRs.

NUG contracts represent PPAs with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of market prices for the current year and next two years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2017, from those used as of December 31, 2016. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2017 and 2016. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	December 31, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,196	$—	$1,196	$—	$1,247	$—	$1,247
Derivative assets - commodity contracts	—	33	—	33	10	200	—	210
Derivative assets - FTRs	—	—	4	4	—	—	7	7
Derivative assets - NUG contracts(1)	—	—	—	—	—	—	1	1
Equity securities(2)	1,104	—	—	1,104	925	—	—	925
Foreign government debt securities	—	88	—	88	—	78	—	78
U.S. government debt securities	—	154	—	154	—	161	—	161
U.S. state debt securities	—	276	—	276	—	246	—	246
Other(3)	589	135	—	724	199	123	—	322
Total assets	$1,693	$1,882	$4	$3,579	$1,134	$2,055	$8	$3,197
Liabilities								
Derivative liabilities - commodity contracts	$—	$(27)	$—	$(27)	$(6)	$(118)	$—	$(124)
Derivative liabilities - FTRs	—	—	(1)	(1)	—	—	(6)	(6)
Derivative liabilities - NUG contracts(1)	—	—	(79)	(79)	—	—	(108)	(108)
Total liabilities	$—	$(27)	$(80)	$(107)	$(6)	$(118)	$(114)	$(238)
Net assets (liabilities)(4)	$1,693	$1,855	$(76)	$3,472	$1,128	$1,937	$(106)	$2,959

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

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $(8) million and $(3) million as of December 31, 2017 and December 31, 2016, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2017 and December 31, 2016:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2016 Balance	$1	$ (137)	$(136)	$8	$ (13)	$(5)
Unrealized gain (loss)	2	(17)	(15)	(6)	(4)	(10)
Purchases	—	—	—	16	(7)	9
Settlements	(2)	46	44	(11)	18	7
December 31, 2016 Balance	$1	$ (108)	$(107)	$7	$ (6)	$1
Unrealized gain (loss)	—	(10)	(10)	1	(2)	(1)
Purchases	—	—	—	4	(1)	3
Settlements	(1)	39	38	(8)	8	—
December 31, 2017 Balance	$—	$ (79)	$(79)	$4	$ (1)	$3

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

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2017:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 3	Model	RTO auction clearing prices	($4.60) to $5.40	$0.70	Dollars/MWH
NUG Contracts	$ (79)	Model	Generation Regional electricity prices	400 to 2,099,000 $30.70 to $32.00	426,000 $30.70	MWH Dollars/MWH

FES

Recurring Fair Value Measurements	December 31, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$720	$—	$720	$—	$726	$—	$726
Derivative assets - commodity contracts	—	33	—	33	10	200	—	210
Derivative assets - FTRs	—	—	1	1	—	—	4	4
Equity securities[(1)]	810	—	—	810	634	—	—	634
Foreign government debt securities	—	65	—	65	—	58	—	58
U.S. government debt securities	—	133	—	133	—	48	—	48
U.S. state debt securities	—	29	—	29	—	3	—	3
Other[(2)]	1	96	—	97	2	81	—	83
Total assets	$811	$1,076	$1	$1,888	$646	$1,116	$4	$1,766
Liabilities								
Derivative liabilities - commodity contracts	$—	$(23)	$—	$(23)	$(6)	$(118)	$—	$(124)
Derivative liabilities - FTRs	—	—	(1)	(1)	—	—	(5)	(5)
Total liabilities	$—	$(23)	$(1)	$(24)	$(6)	$(118)	$(5)	$(129)
Net assets (liabilities)[(3)]	$811	$1,053	$—	$1,864	$640	$998	$(1)	$1,637

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $3 million and $2 million as of December 31, 2017 and December 31, 2016, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2017 and December 31, 2016:

	Derivative Asset	Derivative Liability	Net Asset/(Liability)
	(In millions)		
January 1, 2016 Balance	$5	$ (11)	$ (6)
Unrealized loss	(4)	(3)	(7)
Purchases	10	(5)	5
Settlements	(7)	14	7
December 31, 2016 Balance	$4	$ (5)	$ (1)
Unrealized loss	—	(1)	(1)
Purchases	1	(1)	—
Settlements	(4)	6	2
December 31, 2017 Balance	$1	$ (1)	$ —

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2017:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ —	Model	RTO auction clearing prices	($4.60) to $3.30	$0.10	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and AFS securities.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset against regulatory assets.

During the second quarter of 2017, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in the Beaver Valley Unit 2 and the expiration of the leases, OE and TE transferred NDT assets of $189 million associated with their leasehold interests to NG. See Note 14, "Asset Retirement Obligations," for additional information.

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

AFS Securities

FirstEnergy holds debt and equity securities within its NDT and nuclear fuel disposal trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT and nuclear fuel disposal trusts as of December 31, 2017 and December 31, 2016:

	December 31, 2017(1)			December 31, 2016(2)		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,707	$ 31	$1,738	$1,735	$ 38	$1,773
FES	950	20	970	847	27	874
Equity securities						
FirstEnergy	$949	$ 155	$1,104	$822	$ 103	$925

FES	695	115	810	564	70	634

(1) Excludes short-term cash investments: FirstEnergy - $87 million; FES - $76 million.
(2) Excludes short-term cash investments: FirstEnergy - $61 million; FES - $44 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three years ended December 31, 2017, 2016 and 2015 were as follows:

December 31, 2017	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$2,170	$ 330	$ (253)	$(13)	$ 98
FES	940	256	(195)	(13)	59

December 31, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,678	$ 170	$ (121)	$(21)	$ 100
FES	717	117	(69)	(19)	56

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

Held-To-Maturity Securities

Unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2017 and December 31, 2016 are immaterial to FirstEnergy. Investments in employee benefit trusts and equity method investments totaling $255 million as of December 31, 2017 and $266 million as of December 31, 2016, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt, which excludes capital lease obligations and net unamortized debt issuance costs, premiums and discounts:

	December 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$22,261	$23,038	$19,885	$19,829
FES	2,836	1,487	3,000	1,555

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2017 and December 31, 2016.

11. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility related to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value (unless they meet the normal purchases and normal sales criteria) as follows:

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

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

FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates.

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $10 million and $12 million as of December 31, 2017 and December 31, 2016, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Net unamortized losses to be amortized to income during the next twelve months are not material.

FirstEnergy has used forward starting interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $25 million (FES $3 million) and $33 million (FES $3 million) as of December 31, 2017 and December 31, 2016, respectively. Unamortized losses expected to be amortized to interest expense during the next twelve months are not material.

Refer to Note 3, "Accumulated Other Comprehensive Income," for reclassifications from AOCI during the years ended December 31, 2017 and 2016.

As of December 31, 2017 and December 31, 2016, no commodity or interest rate derivatives were designated as cash flow hedges.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. As of December 31, 2017 and December 31, 2016, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $3 million and $10 million as of December 31, 2017 and December 31, 2016, respectively. During the next twelve months, approximately $2 million of unamortized gains are expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $7 million and $10 million during the years ended December 31, 2017 and 2016, respectively.

As of December 31, 2017 and December 31, 2016, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy’s combustion turbine units. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2017, FirstEnergy's net asset position under commodity derivative contracts was not material. Under these commodity derivative contracts, FES posted $1 million of collateral.

Based on commodity derivative contracts held as of December 31, 2017, an increase in commodity prices of 10% would decrease net income by approximately $6 million (FES $4 million) during the next twelve months.

NUGs

As of December 31, 2017, FirstEnergy's net liability position under NUG contracts was $79 million representing contracts held at JCP&L and PN. Changes in the market value of NUG contracts are subject to regulatory accounting treatment and changes in market values do not impact earnings.

FTRs

As of December 31, 2017, FirstEnergy's and FES' net position associated with FTRs was not material. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of PJM that have load serving obligations.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to PJM, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's Utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets	Fair Value December 31, 2017	Fair Value December 31, 2016	Derivative Liabilities	Fair Value December 31, 2017	Fair Value December 31, 2016
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Other		
Commodity Contracts	$ 33	$ 133	Commodity Contracts	$ (27)	$ (72)
FTRs	4	7	FTRs	(1)	(6)
	37	140		(28)	(78)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs(1)	(79)	(108)
Commodity Contracts	—	77	Noncurrent Liabilities - Other		
FTRs	—	—	Commodity Contracts	—	(52)
NUGs(1)	—	1	FTRs	—	—
	—	78		(79)	(160)
Derivative Assets	$ 37	$ 218	Derivative Liabilities	$ (107)	$ (238)

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

FES records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FES' Consolidated Balance Sheets:

Derivative Assets	Fair Value		Derivative Liabilities	Fair Value	
	December 31, 2017	December 31, 2016		December 31, 2017	December 31, 2016
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$ 33	$ 133	Commodity Contracts	$(23)	$ (72)
FTRs	1	4	FTRs	(1)	(5)
	34	137		(24)	(77)
Deferred Charges and Other Assets - Derivatives			Noncurrent Liabilities - Other		
Commodity Contracts	—	77	Commodity Contracts	—	(52)
	—	77		—	(52)
Derivative Assets	$ 34	$ 214	Derivative Liabilities	$(24)	$ (129)

FirstEnergy enters into contracts with counterparties that allow for the offsetting of derivative assets and derivative liabilities under netting arrangements with the same counterparty. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative assets and derivative liabilities on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

		Amounts Not Offset in Consolidated Balance Sheet		
December 31, 2017	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$33	$ (19)	$ —	$ 14
FTRs	4	(1)	—	3
	$37	$ (20)	$ —	$ 17
Derivative Liabilities				
Commodity contracts	$(27)	$ 19	$ 3	$ (5)
FTRs	(1)	1	—	—
NUG contracts	(79)	—	—	(79)
	$(107)	$ 20	$ 3	$ (84)

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December 31, 2016	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$210	$ (117)	$ —	$93
FTRs	7	(6)	—	1
NUG contracts	1	—	—	1
	$218	$ (123)	$ —	$95
Derivative Liabilities				
Commodity contracts	$(124)	$ 117	$ 1	$(6)
FTRs	(6)	6	—	—
NUG contracts	(108)	—	—	(108)
	$(238)	$ 123	$ 1	$(114)

The following tables summarize the fair value of derivative assets and derivative liabilities on FES' Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

December 31, 2017	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$33	$ (19)	$ —	$ 14
FTRs	1	(1)	—	—
	$34	$ (20)	$ —	$ 14
Derivative Liabilities				
Commodity contracts	$(23)	$ 19	$ —	$ (4)
FTRs	(1)	1	—	—
	$(24)	$ 20	$ —	$ (4)

December 31, 2016	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$210	$ (117)	$ —	$ 93
FTRs	4	(4)	—	—
	$214	$ (121)	$ —	$ 93

Derivative Liabilities				
Commodity contracts	$(124)	$ 117	$ 1	$ (6)
FTRs	(5)	4	1	—
	$(129)	$ 121	$ 2	$ (6)

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The following table summarizes the volumes associated with FirstEnergy’s outstanding derivative transactions as of December 31, 2017:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	2	11	(9)	MWH
FTRs	9	—	9	MWH
NUGs	2	—	2	MWH

The following table summarizes the volumes associated with FES' outstanding derivative transactions as of December 31, 2017:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	2	11	(9)	MWH
FTRs	5	—	5	MWH

The effect of active derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income (Loss) during 2017, 2016 and 2015 are summarized in the following tables:

	Year Ended December 31		
	Commodity Contracts	FTRs	Total
	(In millions)		
2017			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(82)	$ 1	$(81)
Realized Gain (Loss) Reclassified to:			
Revenues	$54	$ (4)	$50
Purchased Power Expense	(17)	—	(17)
Other Operating Expense	—	(14)	(14)
Fuel Expense	5	—	5

	Year Ended December 31		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(14)	$ 5	$(9)
Realized Gain (Loss) Reclassified to:			
Revenues	$210	$ 8	$218

Purchased Power Expense	(131)	—	(131)
Other Operating Expense	—	(35)	(35)
Fuel Expense	(8)	—	(8)

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

The effect of active derivative instruments not in a hedging relationship on FES' Consolidated Statements of Income (Loss) during 2017, 2016 and 2015 are summarized in the following tables:

	Year Ended December 31		
	Commodity Contracts	FTRs	Total
	(In millions)		
2017			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(79)	$ 1	$(78)
Realized Gain (Loss) Reclassified to:			
Revenues	$54	$ (4)	$50
Purchased Power Expense	(17)	—	(17)
Other Operating Expense	—	(14)	(14)

	Year Ended December 31		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(14)	$ 5	$(9)
Realized Gain (Loss) Reclassified to:			
Revenues	$210	$ 8	$218
Purchased Power Expense	(131)	—	(131)
Other Operating Expense	—	(35)	(35)

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	Year Ended December 31		
	Commodity Contracts	FTRs	Total
	(In millions)		
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$93	$(19)	$74
Realized Gain (Loss) Reclassified to:			
Revenues	$111	$49	$160
Purchased Power Expense	(130)	—	(130)
Other Operating Expense	—	(49)	(49)

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during 2017 and 2016. Changes in the value of these contracts are deferred for future recovery from (or credit to) customers:

	Year Ended December 31		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2017	$(107)	$ 2	$(105)
Unrealized loss	(9)	(1)	(10)
Purchases	—	3	3
Settlements	37	(1)	36
Outstanding net asset (liability) as of December 31, 2017	$(79)	$ 3	$(76)
Outstanding net asset (liability) as of January 1, 2016	$(136)	$ 1	$(135)
Unrealized loss	(15)	(3)	(18)
Purchases	—	4	4
Settlements	44	—	44
Outstanding net asset (liability) as of December 31, 2016	$(107)	$ 2	$(105)

12. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2017, FirstEnergy had an accumulated deficit of $(6.3) billion. Dividends declared in 2017 and 2016 were $1.44 per share, which included dividends of $0.36 per share paid in the first, second, third and fourth quarters. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors. On January 16, 2018, the Board of Directors declared a quarterly dividend of $0.36 per share to be paid from other paid-in-capital in the first quarter of 2018.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity-to-total-capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from FERC to pay cash dividends to their respective parents from paid-in capital accounts, as long as their FERC-defined equity-to-total-capitalization ratio remains above 45%. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' abilities to pay cash dividends to FirstEnergy as of December 31, 2017.

Stock Issuance

On January 22, 2018, FirstEnergy entered into agreements for the private placement of its equity securities representing an approximately $2.5 billion investment in the Company. See Note 21, "Subsequent Events," for additional information related to the equity issuances.

FE issued approximately 3.0 million shares of common stock in 2017, 2.7 million shares of common stock in 2016 and 2.5 million shares of common stock in 2015 to registered shareholders and its directors and the employees of its subsidiaries under its Stock Investment Plan and certain share-based benefit plans.

On December 13, 2016, FE contributed 16,097,875 newly issued shares of its common stock to its qualified pension plan in a private placement transaction. These shares were valued at approximately $500 million in the aggregate, and were issued to satisfy a portion of FirstEnergy's future pension funding obligations. The independent fiduciary representing the pension plan with respect to the equity contribution fully liquidated the FE common stock by January 31, 2017.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2017, as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$ 100		
OE	6,000,000	$ 100	8,000,000	no par
OE	8,000,000	$ 25		
Penn	1,200,000	$ 100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$ 100	5,000,000	$ 25
TE	12,000,000	$ 25		
JCP&L	15,600,000	no par		
ME	10,000,000	no par		
PN	11,435,000	no par		
MP	940,000	$ 100		
PE	10,000,000	$ 0.01		
WP	32,000,000	no par		

As of December 31, 2017 and 2016, there were no preferred or preference shares outstanding. See Note 21, "Subsequent Events," for additional information related to preferred stock outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy and FES as of December 31, 2017 and 2016:

	As of December 31, 2017		As of December 31	
(Dollar amounts in millions)	Maturity Date	Interest Rate	2017	2016
FirstEnergy:				
FMBs and secured notes - fixed rate	2018 - 2056	1.726% - 9.740%	$5,446	$5,623
Secured notes - variable rate	2019	4.500%	9	10
Total FMBs and secured notes			5,455	5,633
Unsecured notes - fixed rate	2018 - 2047	2.550% - 7.700%	15,370	13,058
Unsecured notes - variable rate	2020 - 2021	3.227%	1,450	1,200
Total unsecured notes			16,820	14,258
Capital lease obligations			91	104
Unamortized debt discounts			(42)	(25)
Unamortized debt issuance costs			(113)	(87)
Unamortized fair value adjustments			(14)	(6)
Currently payable long-term debt			(1,082)	(1,685)
Total long-term debt and other long-term obligations			$21,115	$18,192
FES:				
Secured notes - fixed rate	2018 - 2047	4.250% - 5.625%	$612	$617
Secured notes - variable rate	2019	4.500%	9	10
Total secured notes			621	627
Unsecured notes - fixed rate	2019 - 2041	2.550% - 6.800%	2,215	2,373
Capital lease obligations			2	8
Unamortized debt discounts			(1)	(1)
Unamortized debt issuance costs			(14)	(15)
Currently payable long-term debt			(524)	(179)
Total long-term debt and other long-term obligations			$2,299	$2,813

On March 1, 2017, FG retired $28 million of PCRBs at maturity.

On March 15, 2017, MP retired $150 million of FMBs at maturity.

On April 3, 2017, CEI retired $130 million of 5.70% senior notes at maturity.

On May 16, 2017, MP issued $250 million of 3.55% FMBs due 2027. Proceeds received from the issuance of the FMBs were used: (i) to repay short-term borrowings, (ii) to fund capital expenditures and (iii) for working capital needs and other general business purposes.

On June 1, 2017, FG repurchased approximately $130 million of PCRBs, which were subject to a mandatory put on such date. FG is currently holding these PCRBs indefinitely.

On June 1, 2017, JCP&L retired $250 million of 5.65% senior notes at maturity.

On June 21, 2017, FE issued the aggregate principal amount of $3.0 billion of its senior notes in three series: $500 million of 2.85% notes due 2022; $1.5 billion of 3.90% notes due 2027; and $1.0 billion of 4.85% notes due 2047. Proceeds from the issuance of the notes were used: (i) to redeem $650 million of FE's 2.75% notes due in 2018 on July 25, 2017, and (ii) for general corporate purposes, including the repayment of short-term borrowings under the FE Facility.

On August 31, 2017, ATSI issued $150 million of 3.66% senior unsecured notes maturing in 2032. Proceeds from the issuance of the notes were used: (i) to repay short-term borrowings, (ii) to fund capital expenditures and (iii) for working capital needs and other general business purposes.

On September 8, 2017, PN issued $300 million of 3.25% senior notes maturing in 2028. Proceeds from the issuance of the notes were used to repay short-term borrowings that were used to repay at maturity $300 million of PN's 6.05% senior notes due September 1, 2017.

On September 15, 2017, WP issued $100 million of 4.09% FMBs due 2047. Proceeds from the issuance of the FMBs were used: (i) to repay short-term borrowings, (ii) to fund capital expenditures and (iii) for other general business purposes.

On October 5, 2017, CEI issued $350 million of 3.50% senior notes maturing in 2028. Proceeds from the issuance of the notes were used: (i) to refinance existing indebtedness, including $300 million of 7.88% FMBs due November 1, 2017, and borrowings outstanding under FirstEnergy's regulated utility money pool and the Facility, (ii) to fund capital expenditures and (iii) for working capital and other general business purposes.

On December 15, 2017, WP issued $275 million of 4.14% FMBs maturing in 2047. Proceeds from the issuance of the FMBs were used to repay at maturity $275 million of WP's 5.95% FMBs due December 15, 2017.

See Note 7, "Leases," for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. As of December 31, 2017 and 2016, $383 million and $406 million of environmental control bonds were outstanding, respectively.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include transition bonds issued by JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. The proceeds were used to securitize the recovery of JCP&L’s bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and to securitize the recovery of deferred costs associated with JCP&L’s supply of BGS. As of December 31, 2017 and 2016, $56 million and $85 million of the transition bonds were outstanding, respectively.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. As of December 31, 2017 and 2016, $315 million and $339 million of the phase-in recovery bonds were outstanding, respectively.

See Note 9, "Variable Interest Entities," for additional information on securitized bonds.

Other Long-term Debt

The Ohio Companies, Penn, FG and NG each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2017, the sinking fund requirement for all FMBs issued under the various mortgage indentures was zero.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2017. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

Year	FirstEnergy	FES
	(In millions)	
2018	$1,051	$515
2019	1,267	323
2020	1,281	667
2021	2,032	674
2022	1,428	284

Certain PCRBs allow bondholders to tender their PCRBs for mandatory purchase prior to maturity. The following table classifies these PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs.

Year	FirstEnergy	FES
	(In millions)	
2018	$375	$375
2019	232	232
2020	490	490
2021	342	342
2022	284	284

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2017, FirstEnergy and FES remain in compliance with all debt covenant provisions.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries, excluding FES and AES, default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FE financing arrangements containing these provisions, defaults by any of AE Supply, FES, FG or NG would generally not cross-default to applicable financing arrangements of FE. Also, defaults by FE would generally not cross-default applicable financing arrangements of any of FE’s subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FE, FG, NG or the Utilities.

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FE and the Utilities and FET and its subsidiaries participate in two separate five-year syndicated revolving credit facilities with aggregate commitments of $5.0 billion (Facilities), which are available through December 6, 2021. FE and the Utilities and FET and its subsidiaries may use borrowings under their Facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt-to-total-capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

FirstEnergy had $300 million and $2,675 million of short-term borrowings as of December 31, 2017 and 2016, respectively. FirstEnergy’s available liquidity from external sources as of January 31, 2018 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2021	$4,000	$ 3,740
FET[2]	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 4,740
		Cash	—	358
		Total	$5,000	$ 5,098

[1] FE and the Utilities. Available liquidity includes impact of $10 million of LOCs issued under various terms.
[2] Includes FET, ATSI, MAIT and TrAIL.

FES had $105 million and $101 million of short-term borrowings as of December 31, 2017 and December 31, 2016, respectively. Of such amounts, $102 million and $101 million, respectively, represents a currently outstanding promissory note due April 2, 2018, payable to AE Supply with any additional short-term borrowings representing borrowings under an unregulated companies' money pool, which also includes FE, FET, FEV and certain other unregulated subsidiaries of FE, but excludes FENOC, FES and its subsidiaries. In addition to FES' access to a separate unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, FES' available liquidity as of January 31, 2018, was as follows:

Type	Commitment	Available Liquidity
	(In millions)	
Two-year secured credit facility with FE	$ 500	$ 500
Cash	—	1
	$ 500	$ 501

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 January 31, 2018:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limits	FET Revolving Credit Facility Sub-Limits	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	300	—	300	(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)

(1) No limitations.
(2) Includes amounts which may be borrowed under the regulated companies' money pool.

$250 million of the FE Facility and $100 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

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

As of December 31, 2017, the borrowers were in compliance with the applicable debt-to-total-capitalization covenants, as well as in the case of FE, the minimum interest coverage ratio requirement, in each case as defined under the respective Facilities.

Separately, in December 2016, FE and FES entered into a two-year secured credit facility in which FE provides a committed line of credit to FES of up to $500 million and additional credit support of up to $200 million to cover surety bonds for $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's Ferry disposal site, respectively. So long as FES remains in an unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, the $500 million secured line of credit provides FES the needed liquidity in order for FES to, among other things, satisfy its nuclear support obligation to NG in the event of extraordinary circumstances with respect to its nuclear facilities. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million). Additionally, FES maintains access to an unregulated companies' money pool, which includes FE, FES' subsidiaries and FENOC, and continues to conduct its ordinary course of business under that money pool in lieu of borrowing under the new facility.

Term Loans

As of December 31, 2017, FE had a $1.2 billion variable rate syndicated term loan and two separate $125 million term loans. On January 22, 2018, FE repaid these term loans in full using the proceeds from the $2.5 billion equity investment.

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. Similar but separate arrangements exist among FirstEnergy's unregulated companies with AE Supply, FE, FET, FEV and certain other unregulated subsidiaries of FE participating in a money pool and FE (as a lender only), FENOC, FES and its subsidiaries participating in a similar money pool. FESC administers these money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as the case may be, 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 2017 was 1.48% per annum for the regulated companies' money pool and 2.30% per annum for the unregulated companies' money pools.

As discussed above, FES currently maintains access to its unregulated companies' money pool in lieu of borrowing under its $500 million secured line of credit. FE expects to provide ongoing liquidity to FES within such unregulated companies' money pool through March 2018. As of December 31, 2017, FES, its subsidiaries, and FENOC had no borrowings in the aggregate under the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2017 and 2016, were as follows:

	2017	2016
FirstEnergy	3.24%	2.47%

14. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities and totaled $1,758 million and $713 million as of December 31, 2017 and 2016, respectively. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2017 and 2016 were as follows:

	2017	2016
	(In millions)	
FirstEnergy	$2,678	$2,514
FES	$1,856	$1,552

The following table summarizes the changes to the ARO balances during 2017 and 2016:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2016	$1,410	$831
Liabilities settled	(27)	(18)
Accretion	95	56
Liabilities Incurred	4	32
Balance, December 31, 2016	$1,482	$901
Changes in timing of estimated cash flows [1]	944	944
Liabilities settled	(12)	(11)
Accretion	101	62
Liabilities Incurred	—	49
Balance, December 31, 2017	$2,515	$1,945

[1] See Note 2, "Asset Sales and Impairments" for further discussion.

During the second quarter of 2017, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in the Beaver Valley Unit 2 sale leaseback and the expiration of the leases, OE and TE transferred the ARO (included within the FES liabilities incurred above) and NDT assets associated with their leasehold interests to NG, with the difference of $73 million credited to the common stock of FES.

During 2016, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in Perry Unit 1, OE transferred the ARO (included within the FES liabilities incurred above) and related NDT assets associated with the leasehold interest to NG with the difference of $28 million credited to the common stock of FES. As of June 30, 2016, NG owns 100% of Perry Unit 1.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, 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.

15. REGULATORY MATTERS

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the

NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Maryland, Michigan, New Jersey and Illinois, 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.

Following the adoption of the Tax Act, various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities’ rates and charges. State proceedings which have arisen are discussed below. The Utilities continue to monitor and investigate the impact of state regulatory impacts resulting from the Tax Act.

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. 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 achieved under PE's current plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER Maryland program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. The costs of PE's 2015-2017 plan approved by the MDPSC in December 2014 were approximately $60 million. PE filed its 2018-2020 EmPOWER Maryland plan on August 31, 2017. The 2018-2020 plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. On December 22, 2017, the MDPSC issued an order approving the 2018-2020 plan with various modifications. PE recovers 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 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. Comments were filed and a hearing was held in late 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. On January 19, 2018, PE filed a joint petition, along with other utility companies, work group stakeholders, and the

MDPSC electric vehicle work group leader, to implement a statewide electric vehicle portfolio. If approved, PE will launch an electric vehicle charging infrastructure program on January 1, 2019, offering up to 2,000 rebates for electric vehicle charging equipment to residential customers, and deploying up to 259 chargers at non-residential customer service locations at a projected total cost of $12 million. PE is proposing to recover program costs subject to a five-year amortization. On February 6, 2018, the MDPSC opened a new proceeding to consider the petition and directed that comments be filed by March 16, 2018.

On January 12, 2018, the MDPSC instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of Maryland utilities. PE must track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and submitted a report to the MDPSC on February 15, 2018, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers and proposed to file a base rate case in the third quarter of 2018 where the benefits from the effects of the Tax Act will be realized by customers through a lower rate increase than would otherwise be necessary.

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.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended 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. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L’s 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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 included 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, 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 Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On December 19, 2017, the NJBPU approved the issuance of proposed rules to modify the CTA methodology consistent with its October 22, 2014 Generic Order. The proposed rule was published in the NJ Register on January 16, 2018, and was republished on February 6, 2018, to correct an error. Interested parties have sixty days to comment on the proposed rulemaking.

At the December 19, 2017 NJBPU public meeting, the NJBPU approved its IIP rulemaking. The IIP creates a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety. JCP&L expects to make a filing in 2018.

On January 31, 2018, the NJBPU instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of New Jersey utilities. JCP&L must track and apply regulatory accounting treatment for the impacts effective January 1, 2018, and file a petition with the NJBPU by March 2, 2018, regarding the expected impacts of the Tax Act on JCP&L’s expenses and revenues and how the effects will be passed through to its customers.

OHIO

The Ohio Companies currently operate under ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO’s Opinion and Order issued on March 31, 2016 and Fifth Entry on Rehearing on 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. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $204 million annually. Revenues from 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 $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: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016, and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates (which filing was made on April 3, 2017, and remains pending).

Several parties, including the Ohio Companies, filed applications for rehearing regarding 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 August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies’ challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO’s August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the Ohio Manufacturer's Association Energy Group filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. On November 16, 2017, the Ohio Companies intervened in the appeal. Additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. For additional information, see “FERC Matters - Ohio ESP IV PPA,” below.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. 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 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. 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. On November 21, 2017, the PUCO issued an order that approved the filed Stipulation and Recommendation with several modifications, including a cap on the Ohio Companies’ collection of program costs and shared savings set at 4% of the Ohio Companies’ total sales to customers as reported on FERC Form 1. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO’s modification of the Stipulation and Recommendation to include the 4% cost cap, which was denied by the PUCO on January 10, 2018.

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 that in 2014 SB310 froze 2015 and 2016 requirements at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. 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. The OCC and the ELPC also filed appeals of the PUCO's order. On January 24, 2018, the Supreme Court of Ohio reversed the PUCO order finding that the order violated the rule against prohibiting retroactive ratemaking. On February 5, 2018, the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition on February 15, 2018.

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. On March 29, 2017, the PUCO issued a Second Entry on Rehearing that granted, in part, the applications for rehearing filed by FES and other parties, finding that the PUCO's guidelines regarding fixed-price contracts should not apply to large mercantile customers. This finding changes the original order, which applied the guidelines to all customers, including mercantile customers. The PUCO also reaffirmed several provisions of the original order, including that the fixed-price guidelines only apply on a going-forward basis and not to existing contracts and that regulatory-out clauses in contracts are permissible.

On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan. The DPM Plan is a portfolio of approximately $450 million in distribution platform investment projects, which are designed to modernize the Ohio Companies' distribution grid, prepare it for further grid modernization projects, and provide customers with immediate reliability benefits. The Ohio Companies have requested that the PUCO issue an order approving the DPM Plan and associated cost recovery no later than May 2, 2018, so that the Ohio Companies can expeditiously commence the DPM Plan and customers can begin to realize the associated benefits.

On January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act and determine the appropriate course of action to pass benefits on to customers. The Ohio Companies must establish a regulatory liability, effective January 1, 2018, for the estimated reduction in federal income tax resulting from the Tax Act, and filed comments on February 15, 2018, explaining that customers will save nearly $40 million annually as a result of updating tariff riders for the tax rate changes and that the Ohio Companies’ base distribution rates are not impacted by the Tax Act changes because they are frozen through May 2024.

PENNSYLVANIA

The Pennsylvania Companies operate under 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 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. The DSPs include modifications to the Pennsylvania Companies’ POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

On December 11, 2017, the Pennsylvania Companies filed DSPs for the June 1, 2019 through May 31, 2023 delivery period. Under the 2019-2023 DSPs, the supply is proposed to be provided by wholesale suppliers through a mix of 3, 12 and 24-month energy contracts, as well as two RFPs for 2-year SREC contracts for ME, PN and Penn. The 2019-2023 DSPs as proposed also include modifications to the Pennsylvania Companies’ POR programs in order to continue their clawback pilot program as a long-term, permanent program term. The 2019-2023 DSPs also introduce a retail market enhancement rate mechanism designed to stimulate residential customer shopping, and modifications to the Pennsylvania Companies’ customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW. A hearing has been scheduled for April 10-11, 2018, and the PPUC is expected to issue a final order on these DSPs by mid-September 2018.

The Pennsylvania Companies operate under rates that were approved by the PPUC on January 19, 2017, effective as of January 27, 2017. These rates provide annual increases in operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are intended to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements.

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. 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 February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the remaining period of 2018 to 2020, as modified, are: WP $50.1 million; PN $44.8 million; Penn $33.2 million; and ME $51.3 million.

On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery, which were approved by the PPUC on June 9, 2016, and went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. On January 19, 2017, in the PPUC's order approving the Pennsylvania Companies' general rate cases, the PPUC added an additional issue to the DSIC proceeding to include whether ADIT should be included in DSIC calculations. On February 2, 2017, the parties to the DSIC proceeding submitted a Joint Settlement to the ALJ that resolved the issues that were pending from the order issued on June 9, 2016, which is pending PPUC approval. The ADIT issue is subject to further litigation and a hearing was held on May 12, 2017. On August 31, 2017, the ALJ issued a decision recommending that the complaint of the Pennsylvania OCA be granted by the PPUC such that the Pennsylvania Companies reflect all federal and state income tax deductions related to DSIC-eligible property in the currently effective DSIC rates. If the decision is approved by the PPUC, the impact is not expected to be material to FirstEnergy. The Pennsylvania Companies filed exceptions to the decision on September 20, 2017, and reply exceptions on October 2, 2017.

On February 12, 2018, the PPUC initiated a proceeding to determine the effects of the Tax Act on the tax liability of utilities and the feasibility of reflecting such impacts in rates charged to customers. By March 9, 2018, the Pennsylvania Companies must submit information to the PPUC to calculate the net effect of the Tax Act on income tax expense and rate base, and comments addressing whether rates should be adjusted to reflect the tax rate changes, and if so, how and when such modifications should take effect.

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 September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of 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. On December 15, 2017, the WVPSC approved MP's and PE's proposed annual decrease in their EE&C rates, effective January 1, 2018, which is not material to FirstEnergy.

On December 9, 2016, the WVPSC approved the annual ENEC case for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, resulting in an increase in the ENEC rate of $25 million annually beginning January 1, 2017. In addition, ENEC rates will be maintained at the same level for a two year period.

On December 30, 2015, MP and PE 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. On December 16, 2016, MP issued an RFP to address its generation shortfall, 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. AE Supply was the winning bidder of the RFP to address MP’s generation shortfall and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire AE Supply’s Pleasants Power Station (1,300 MWs) for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals. In addition, on March 7, 2017, MP and PE filed an application with the WVPSC and MP and AE Supply filed an application with FERC requesting authorization for such purchase. Various intervenors filed protests challenging the RFP and requesting FERC deny the application, set it for hearing to allow discovery into the RFP process, or delay an order pending the conclusion of the WVPSC proceeding. On January 12, 2018, FERC issued an order denying authorization for the transaction, holding that MP and AE Supply did not demonstrate that the sale was consistent with the public interest and the transaction did not fall within the safe harbors for meeting FERC’s affiliate cross-subsidization analysis. In the order FERC also revised and clarified certain details of its standards for the review of transactions resulting from competitive solicitations, and concluded that MP’s RFP did not meet the revised and clarified standards. FERC allowed that MP may submit a future application for a transaction resulting from a new RFP. The WVPSC issued its order on January 26, 2018, denying the petition as filed but granting the transfer of Pleasants Power Station under certain conditions, which included MP assuming significant commodity risk. MP, PE and AE Supply have determined not to seek rehearing at FERC in light of the adverse decisions at FERC and the WVPSC. Based on the FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement. With respect to the Bath County RFP, MP does not plan to move forward with that sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

On September 1, 2017, MP and PE filed with the WVPSC for a reconciliation of their VMS to confirm that rate recovery matches VMP costs and for a regular review of that program. MP and PE proposed a $15 million annual decrease in VMS rates effective January 1, 2018, and an additional $15 million decrease in rates for 2019. This is an overall decrease in total revenue and average rates of 1%. On December 15, 2017, the WVPSC issued an order adopting a unanimous settlement without modification.

On January 3, 2018, the WVPSC initiated a proceeding to investigate the effects of the Tax Act on the revenue requirements of utilities. MP and PE must track the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018, and file written testimony explaining the impact of the Tax Act on federal income tax and revenue requirements by May 30, 2018. On January 26, 2018, the WVPSC issued an order clarifying that regulatory accounting should be implemented as of January 1, 2018, including the recording of any regulatory liabilities resulting from the Tax Act.

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 certain of its subsidiaries, AE Supply, FENOC, ATSI, MAIT 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, but subsequently agreed to suspend it and advised FERC of this course of action.

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. On August 30, 2017, the generation owners requested expedited action by FERC. 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. FirstEnergy and certain of the other parties responded to such opposition. On October 20, 2017, the settling and non-opposing parties requested expedited action by FERC. 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, ATSI resolved a dispute regarding responsibility for certain costs for the “Michigan Thumb” transmission project. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. 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. The MISO TOs subsequently filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened and participated in the proceedings on behalf of ATSI, the Ohio Companies and Penn. On June 21, 2017, the Sixth Circuit issued its decision denying the MISO TOs' appeal request. MISO and the MISO TOs did not seek review by the U.S. Supreme Court, effectively resolving the dispute over the "Michigan Thumb" transmission project. 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 MVP costs and "legacy RTEP" transmission projects cannot be predicted at this time.

Transfer of Transmission Assets to MAIT

Following receipt of necessary regulatory approvals, on January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and transmission asset contributions. MAIT, a transmission-only subsidiary of FET, owns and operates all of the FERC-jurisdictional transmission assets previously owned by ME and PN. Subsequently, on March 13, 2017, FERC issued an order authorizing MAIT to issue short- and long-term debt securities, permitting MAIT to participate in the FirstEnergy regulated companies’ money pool for working capital, to fund day-to-day operations, support capital investment and establish an actual capital structure for ratemaking purposes.

MAIT Transmission Formula Rate

On October 28, 2016, as amended on January 10, 2017, 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 February 1, 2017. 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. On March 10, 2017, FERC issued an order accepting the MAIT formula transmission rate for filing, suspending the formula transmission rate for five months to become effective July 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, MAIT requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. MAIT’s rates went into effect on July 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC. The settlement agreement provides for certain changes to MAIT's formula rate, changes MAIT's ROE from 11% to 10.3%, sets the recovery amount for certain regulatory assets, and establishes that MAIT's capital structure will not exceed 60% equity over the period ending December 31, 2021. The settlement agreement further provides that the ROE and the 60% cap on the equity component of MAIT's capital structure will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2022. The settlement agreement currently is pending at FERC. As a result of the settlement agreement, MAIT recognized a pre-tax impairment charge of $13 million in the third quarter of 2017.

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. 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 March 10, 2017, FERC issued an order accepting the JCP&L formula transmission rate for filing, suspending the transmission rate for five months to become effective June 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, JCP&L requested rehearing of FERC's decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. JCP&L's rates went into effect on June 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On December 21, 2017, JCP&L and certain parties filed a settlement agreement with FERC. The settlement agreement provides for a $135 million stated annual revenue requirement for Network Integration Transmission Service and an average of $20 million stated annual revenue requirement for certain projects listed on the PJM Tariff where the costs are allocated in part beyond the JCP&L transmission zone within the PJM Region. The revenue requirements are subject to a moratorium on additional revenue requirements proceedings through December 31, 2019, other than limited filings to seek recovery for certain additional costs. Also on December 21, 2017, JCP&L filed a motion for authorization to implement the settlement rate on an interim basis. On December 27, 2017, FERC granted the motion authorizing JCP&L to implement the settlement rate effective January 1, 2018, pending a final commission order on the settlement agreement. The settlement agreement is pending at FERC. As a result of the settlement agreement, JCP&L recognized a pre-tax impairment charge of $28 million in the fourth quarter of 2017.

DOE NOPR: Grid Reliability and Resilience Pricing

On September 28, 2017, the Secretary of Energy released a NOPR requesting FERC to issue rules directing RTOs to incorporate pricing for defined “eligible grid reliability and resiliency resources” into wholesale energy markets. Specifically, as proposed, RTOs would develop and implement tariffs providing a just and reasonable rate for energy purchases from eligible grid reliability and resiliency resources and the recovery of fully allocated costs and a fair ROE. The NOPR followed the August 23, 2017, release of the DOE’s study regarding whether federally controlled wholesale energy markets properly recognize the importance of coal and nuclear plants for the reliability of the high-voltage grid, as well as whether federal policies supporting renewable energy sources have harmed the reliability of the energy grid. The DOE requested for the final rules to be effective in January 2018.

On October 2, 2017, FERC established a docket and requested comments on the NOPR. FESC and certain of its affiliates submitted comments and reply comments. On January 8, 2018, FERC issued an order terminating the NOPR proceeding, finding that the NOPR did not satisfy the statutory threshold requirements under the FPA for requiring changes to RTO/ISO tariffs to address resilience concerns. FERC in its order instituted a new administrative proceeding to gather additional information regarding resilience issues, and directed that each RTO/ISO respond to a provided list of questions. There is no deadline or requirement for FERC to act in this new proceeding. At this time, we are uncertain as to the potential impact that final action by FERC, if any, would have on FES and our strategic options, and the timing thereof, with respect to the competitive business.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. 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 hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017, and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC, seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers commented on the compliance filing, alleging inaccuracies in and lack of transparency of data and information in the compliance filing, and requested that PATH be directed to recalculate the refund provided in the filing. PATH responded to these comments in a filing that was submitted on May 22, 2017. On July 27, 2017, FERC Staff issued a letter to PATH requesting additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH filed its response on September 27, 2017. FERC orders on PATH's requests for rehearing and compliance filing remain pending.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and certain of its subsidiaries, Buchanan Generation and Green Valley 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 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. On July 27, 2017, FERC accepted the triennial filing as submitted.

16. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.4 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $450 million; and (ii) $13.0 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 and NG's maximum potential assessment under these provisions would be $509 million per incident but not more than $76 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 yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.4 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.

As of December 31, 2017, outstanding guarantees and other assurances aggregated approximately $3.8 billion, consisting of parental guarantees ($1.2 billion), subsidiaries' guarantees ($1.8 billion), other guarantees ($275 million) and other assurances ($459 million).

Of the aggregate amount, substantially all relates to guarantees of wholly-owned consolidated entities of FirstEnergy. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG and NG would have claims against each of FES, FG and NG, regardless of whether their primary obligor is FES, FG or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

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

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on CES' power portfolio exposure as of December 31, 2017, FES has posted collateral of $123 million and AE Supply has posted collateral of $4 million. The Regulated Distribution Segment has posted collateral of $4 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, 2017:

Potential Collateral Obligations	FES	AE Supply	Regulated	FE Corp	Total
	(In millions)				
Contractual Obligations for Additional Collateral					
At Current Credit Rating	$4	$ 1	$ —	$—	$5
Upon Further Downgrade	—	—	41	—	41
Surety Bonds (Collateralized Amount)[1]	16	1	107	237	361
Total Exposure from Contractual Obligations	$20	$ 2	$ 148	$237	$407

[1] Surety Bonds are not tied to a credit rating. Surety Bonds' impact assumes maximum contractual obligations (typical obligations require 30 days to cure). FE provides credit support for FG surety bonds for $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's Ferry disposal site, respectively.

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2017, FES has $2 million of collateral posted with its affiliates.

OTHER COMMITMENTS AND CONTINGENCIES

FE is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding's outstanding principal balance is $275 million. In addition to FE, 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.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition.

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 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 the EPA’s regulatory approach under CSAPR, but questioning whether the EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. The 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. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, the EPA’s reconsideration of the CSAPR update rule and how the EPA and the states ultimately 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.

The EPA missed the October 1, 2017, deadline and has not yet promulgated the attainment designations. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. On December 5, 2017, fourteen states and the District of Columbia filed complaints in the U.S. District Court of Northern California seeking an order that the EPA promulgate the attainment designations for 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, but has not taken any further action. On January 2, 2018, the State of Delaware provided the EPA a notice required at least 60 days prior to filing a suit seeking to compel the EPA to either approve or deny the August 2016 CAA Section 126 petition. 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, but has not taken any further action. On September 27, 2017, and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the U.S. District Court for the District of Maryland seeking an order that the EPA either approve or deny the CAA Section 126 petition of November 16, 2016. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

MATS imposed emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired EGUs effective in April 2015 with averaging of emissions from multiple units located at a single plant. The majority of FirstEnergy's MATS compliance program and related costs have been completed.

On August 3, 2015, FG, a wholly owned 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 arose 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. 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 hearing in November and December 2016. On April 12, 2017, the arbitration panel ruled on liability in favor of BNSF and CSX. In the liability award, the panel found, among other things, that FG's demand for declaratory judgment that force majeure excused FG's performance was denied, that FG breached and repudiated the coal transportation contract and that the panel retains jurisdiction of claims for liquidated damages for the years 2015-2025. On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to this consolidated proceeding on the terms and conditions set forth below. Pursuant to the settlement agreement, FG will pay CSX and BNSF an aggregate amount equal to $109 million, which is payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provides that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. Further, FE and FG, and CSX and BNSF, agreed to release, waive and discharge each other from any further obligations under the claims covered by the settlement agreement upon payment in full of the settlement amount. Until such time, CSX and BNSF will retain the claims covered by the settlement agreement and in the event of a bankruptcy proceeding with respect to FG, to the extent the remaining settlement payments are not paid in full by FG or FE, CSX and BNSF shall be entitled to seek damages for such claims in an amount to be determined by the arbitration panel or otherwise agreed by the parties.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS which 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 generating station. 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 liquidated damages through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. The arbitration hearing is scheduled for June 2018. The parties have exchanged settlement proposals to resolve all claims related to this proceeding, however, discussions have been terminated and settlement is unlikely. FirstEnergy and FES recorded a pre-tax charge of $116 million in 2017 based on an estimated range of losses regarding the ongoing litigation with respect to this agreement. If the case proceeds to arbitration, the amount of damages owed to BNSF and NS could be materially higher and may cause FES to seek protection under U.S. bankruptcy laws. FG intends to vigorously assert its position in this arbitration proceeding, and 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.

As to a specific coal supply agreement, AE Supply, the party thereto, asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, on January 15, 2015, Tunnel Ridge, LLC, the coal supplier, commenced litigation in the Court of Common Pleas of Allegheny County, Pennsylvania, alleging AE Supply did not have sufficient justification to terminate the agreement and seeking damages for the difference between the market and contract price of the coal, or lost profits plus incidental damages. AE Supply filed an answer denying any liability related to the termination. On May 1, 2017, the complaint was amended to add FE, FES and FG, although not parties to the underlying contract, as defendants and to seek additional damages based on new claims of fraud, unjust enrichment, promissory estoppel and alter ego. On June 27, 2017, after oral argument, defendants' preliminary objections to the amended complaint were denied. On February 18, 2018, the parties reached an agreement in principle settling all claims in dispute. The agreement in principle includes, among other matters, a $93 million payment by AE Supply, as well as certain coal supply commitments for Pleasants Power Station during its remaining operation by AE Supply. Certain aspects of the final settlement agreement will be guaranteed by FE, including the $93 million payment.

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, the 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, the 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 U.S. 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 CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel-fired EGUs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired EGUs. Numerous states and private parties filed appeals and motions to stay the CPP with 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. On March 28, 2017, an executive order, entitled “Promoting Energy Independence and Economic Growth,” instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, 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 GHG emissions by 26 to 28 percent below 2005 levels by 2025 and in September 2016, 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 became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. 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

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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. Depending on any final action taken by the states with respect to impingement and entrainment, 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 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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. 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 CCRs, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, 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. The Sierra Club's Notices of Appeal before the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility were resolved through a Consent Adjudication between FG, PA DEP and the Sierra Club requiring operational changes that became effective November 3, 2017.

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, 2017, 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 $125 million have been accrued through December 31, 2017. Included in the total are accrued liabilities of approximately $80 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2017, FirstEnergy had approximately $2.7 billion (FES $1.9 billion) invested in external trusts to be used for the decommissioning and environmental remediation of its nuclear generating facilities. The values of FirstEnergy's NDTs also fluctuate based on market conditions. If the values 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.

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. In 2017, FENOC commenced a multi-year effort to implement repairs to the shield building. In addition to these ongoing repairs, FENOC intends to submit a license amendment application to the NRC to reconcile the shield building laminar cracking concern.

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. So long as FES remains in the unregulated companies' money pool, the $500 million secured line of credit with FE discussed above provides FES the needed liquidity in order for FES to satisfy its nuclear support obligations 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.

17. TRANSACTIONS WITH AFFILIATED COMPANIES

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

FirstEnergy's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements and provide power to certain affiliates' facilities. The primary affiliated company transactions for FES during the three years ended December 31, 2017 are as follows:

FES	2017	2016	2015
	(In millions)		
Revenues:			
Electric sales to affiliates	$366	$459	$666
Other	11	11	14
Expenses:			
Purchased power from affiliates	201	622	353
Fuel	4	4	1
Support services	775	748	705
Investment Income:			
Interest income from FE	13	2	2
Interest Expense:			
Interest expense to affiliates	—	5	4
Interest expense to FE	19	2	3

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are charged to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Intercompany transactions are generally settled under commercial terms within thirty days. FES purchases the entire output of the generation facilities owned by FG and NG. Prior to June 1, 2017, FES purchased the output relating to leasehold interests of OE and TE in certain of those facilities that were 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 terminated the PSA effective on April 1, 2017.

Additionally, FES and AE Supply are parties to an affiliated commodity transfer agreement in which AE Supply sells coal to FES in accordance with the terms and conditions set forth under the respective coal purchase agreements that AE Supply has with a third party. During 2017, AE Supply sold 0.4 million tons of coal for $15 million to FES at market prices. During 2016 and 2015, AE Supply sold 1.5 million and 1.2 million tons of coal to FES, respectively, at its cost of $80 million and $63 million, respectively. During 2017 and 2016, FES sold 1.1 million and 0.4 million tons of coal to AE Supply, respectively, for $41 million and $16 million, respectively, at market prices. Also during 2016, FES sold 0.7 million tons of coal to MP for $31 million at market prices. FES had no intercompany sales of coal to AE Supply or MP in 2015.

FES and the Utilities are parties to an intercompany income tax allocation agreement with FE and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FE are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see Note 6, "Taxes").

18. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG, a 100% owned subsidiary of FES, completed a sale and leaseback transaction for a 93.83% undivided interest in Bruce Mansfield Unit 1. FG's parent company, FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FG or its parent company, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the years ended December 31, 2017, 2016, and 2015, Condensed Consolidating Balance Sheets as of December 31, 2017 and December 31, 2016, and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2017, 2016, and 2015, for the parent and guarantor and non-guarantor subsidiaries are presented below. These statements are provided as FG's parent company fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by the parent company using the equity method. Results of operations for FG and NG are, therefore, reflected in their parent company's investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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

For the Year Ended December 31, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$3,037	$1,062	$1,362	$ (2,363)	$ 3,098
OPERATING EXPENSES:					
Fuel	—	390	209	—	599
Purchased power from affiliates	2,488	—	76	(2,363)	201
Purchased power from non-affiliates	628	—	—	—	628
Other operating expenses	322	490	653	49	1,514
Pension and OPEB mark-to-market adjustment	(12)	(30)	66	—	24
Provision for depreciation	12	32	67	(2)	109
General taxes	20	21	17	—	58
Impairment of assets and related charges	—	—	2,031	—	2,031
Total operating expenses	3,458	903	3,119	(2,316)	5,164
OPERATING INCOME (LOSS)	(421)	159	(1,757)	(47)	(2,066)
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income (loss) from equity investees	(1,864)	39	113	1,806	94
Miscellaneous income	1	1	5	—	7
Interest expense — affiliates	(75)	(11)	(1)	68	(19)
Interest expense — other	(46)	(104)	(44)	56	(138)
Capitalized interest	—	2	24	—	26
Total other income (expense)	(1,984)	(73)	97	1,930	(30)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(2,405)	86	(1,660)	1,883	(2,096)
INCOME TAXES (BENEFITS)	(14)	360	(78)	27	295
NET INCOME (LOSS)	$(2,391)	$(274)	$(1,582)	$ 1,856	$ (2,391)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(2,391)	$(274)	$(1,582)	$ 1,856	$ (2,391)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(14)	(13)	—	13	(14)
Amortized gain on derivative hedges	2	—	—	—	2
Change in unrealized gain on available-for-sale securities	30	—	30	(30)	30
Other comprehensive income (loss)	18	(13)	30	(17)	18
Income taxes (benefits) on other comprehensive income (loss)	6	(5)	10	(5)	6

Other comprehensive income (loss), net of tax	12	(8)	20	(12)	12
COMPREHENSIVE INCOME (LOSS)	$(2,379)	$(282)	$(1,562)	$ 1,844	$ (2,379)

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

For the Year Ended December 31, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$4,242	$1,739	$2,004	$ (3,587)	$ 4,398
OPERATING EXPENSES:					
Fuel	—	582	198	—	780
Purchased power from affiliates	4,024	—	187	(3,587)	624
Purchased power from non-affiliates	1,020	—	—	—	1,020
Other operating expenses	310	286	632	49	1,277
Pension and OPEB mark-to-market adjustment	(1)	(4)	53	—	48
Provision for depreciation	13	120	206	(3)	336
General taxes	31	30	27	—	88
Impairment of assets and related charges	39	3,937	4,729	(83)	8,622
Total operating expenses	5,436	4,951	6,032	(3,624)	12,795
OPERATING LOSS	(1,194)	(3,212)	(4,028)	37	(8,397)
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income (loss) from equity investees	(4,585)	30	84	4,538	67
Miscellaneous income	4	3	—	—	7
Interest expense — affiliates	(50)	(10)	(4)	57	(7)
Interest expense — other	(55)	(105)	(44)	57	(147)
Capitalized interest	—	8	26	—	34
Total other income (expense)	(4,686)	(74)	62	4,652	(46)
LOSS BEFORE INCOME TAX BENEFITS	(5,880)	(3,286)	(3,966)	4,689	(8,443)
INCOME TAX BENEFITS	(425)	(1,169)	(1,429)	35	(2,988)
NET LOSS	$(5,455)	$(2,117)	$(2,537)	$ 4,654	$ (5,455)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET LOSS	$(5,455)	$(2,117)	$(2,537)	$ 4,654	$ (5,455)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(14)	(14)	—	14	(14)
Amortized gain on derivative hedges	—	—	—	—	—
Change in unrealized gain on available-for-sale securities	52	—	52	(52)	52
Other comprehensive income (loss)	38	(14)	52	(38)	38
Income taxes (benefits) on other comprehensive income (loss)	15	(5)	20	(15)	15

Other comprehensive income (loss), net of tax	23	(9)	32	(23)	23
COMPREHENSIVE LOSS	$(5,432)	$(2,126)	$(2,505)	$ 4,631	$ (5,432)

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

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$4,824	$1,801	$2,138	$ (3,758)	$ 5,005
OPERATING EXPENSES:					
Fuel	—	679	192	—	871
Purchased power from affiliates	3,826	—	285	(3,758)	353
Purchased power from non-affiliates	1,684	—	—	—	1,684
Other operating expenses	378	273	608	49	1,308
Pension and OPEB mark-to-market adjustment	(8)	10	55	—	57
Provision for depreciation	12	124	191	(3)	324
General taxes	45	26	27	—	98
Impairment of assets and related charges	21	2	10	—	33
Total operating expenses	5,958	1,114	1,368	(3,712)	4,728
OPERATING INCOME (LOSS)	(1,134)	687	770	(46)	277
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income (loss) from equity investees	844	17	(5)	(870)	(14)
Miscellaneous income	1	2	—	—	3
Interest expense — affiliates	(29)	(8)	(4)	34	(7)
Interest expense — other	(52)	(104)	(49)	58	(147)
Capitalized interest	—	6	29	—	35
Total other income (expense)	764	(87)	(29)	(778)	(130)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(370)	600	741	(824)	147
INCOME TAXES (BENEFITS)	(452)	224	278	15	65
NET INCOME	$82	$376	$463	$ (839)	$ 82
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$82	$376	$463	$ (839)	$ 82
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	(9)	—	(8)	8	(9)
Other comprehensive loss	(18)	(5)	(8)	13	(18)
Income tax benefits on other comprehensive loss	(7)	(2)	(3)	5	(7)
Other comprehensive loss, net of tax	(11)	(3)	(5)	8	(11)

COMPREHENSIVE INCOME	$71	$373	$458	$ (831)	$ 71

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$1	$—	$ —	$ 1
Receivables-					
Customers	181	—	—	—	181
Affiliated companies	210	80	260	(326)	224
Other	13	8	—	—	21
Notes receivable from affiliated companies	366	1,744	1,512	(3,622)	—
Materials and supplies	41	142	—	—	183
Derivatives	34	—	—	—	34
Collateral	105	25	—	—	130
Prepaid taxes and other	10	12	—	—	22
	960	2,012	1,772	(3,948)	796
PROPERTY, PLANT AND EQUIPMENT:					
In service	122	2,646	8	(281)	2,495
Less — Accumulated provision for depreciation	65	1,947	—	(189)	1,823
	57	699	8	(92)	672
Construction work in progress	3	19	—	—	22
	60	718	8	(92)	694
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,856	—	1,856
Investment in affiliated companies	1,153	—	—	(1,153)	—
Other	—	9	—	—	9
	1,153	9	1,856	(1,153)	1,865
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	267	790	890	(193)	1,754
Property taxes	—	9	16	—	25
Other	45	310	—	25	380
	312	1,109	906	(168)	2,159
	$2,485	$3,848	$4,542	$ (5,361)	$ 5,514
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$438	$114	$ (28)	$ 524
Short-term borrowings - affiliated companies	3,325	402	—	(3,622)	105
Accounts payable-					
Affiliated companies	320	60	194	(319)	255
Other	22	83	—	—	105
Accrued taxes	52	12	21	(13)	72
Derivatives	22	2	—	—	24
Other	44	73	11	41	169
	3,785	1,070	340	(3,941)	1,254

CAPITALIZATION:					
Total equity (deficit)	(2,070)	547	528	(1,075)	(2,070)
Long-term debt and other long-term obligations	691	1,666	1,007	(1,065)	2,299
	(1,379)	2,213	1,535	(2,140)	229
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	723	723
Retirement benefits	28	125	—	—	153
Asset retirement obligations	—	187	1,758	—	1,945
Other	51	253	909	(3)	1,210
	79	565	2,667	720	4,031
	$2,485	$3,848	$4,542	$ (5,361)	$ 5,514

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	213	—	—	—	213
Affiliated companies	332	315	417	(612)	452
Other	17	2	8	—	27
Notes receivable from affiliated companies	501	1,585	1,294	(3,351)	29
Materials and supplies	45	142	80	—	267
Derivatives	137	—	—	—	137
Collateral	157	—	—	—	157
Prepaid taxes and other	38	24	1	—	63
	1,440	2,070	1,800	(3,963)	1,347
PROPERTY, PLANT AND EQUIPMENT:					
In service	120	2,524	4,703	(290)	7,057
Less — Accumulated provision for depreciation	52	1,920	4,144	(187)	5,929
	68	604	559	(103)	1,128
Construction work in progress	2	67	358	—	427
	70	671	917	(103)	1,555
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,552	—	1,552
Investment in affiliated companies	2,923	—	—	(2,923)	—
Other	—	9	1	—	10
	2,923	9	1,553	(2,923)	1,562
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits					