FIRSTENERGY CORP
Form 10-K
February 19, 2019

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, 2018

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

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:
None.

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files).
Yes þ No o

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. o
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

Accelerated Filer o

Non-accelerated Filer o

Smaller Reporting Company o

Emerging Growth Company o
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
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.
$17,109,706,919 as of June 30, 2018
Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date:

CLASS	AS OF JANUARY 31, 2019
Common Stock, $0.10 par value	530,152,175

Documents Incorporated By Reference

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2019 Annual Meeting of Shareholders of FirstEnergy Corp. to be held May 21, 2019	Part III

TABLE OF CONTENTS

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, a subsidiary of FirstEnergy Corp.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, formerly a generation subsidiary of AE Supply that became a wholly owned subsidiary of MP in May 2018
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
BSPC	Bay Shore Power Company
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, formerly a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FirstEnergy License Holding Company
FENOC	FirstEnergy Nuclear Operating Company, a subsidiary of FE, which operates NG's nuclear generating facilities
FES	FirstEnergy Solutions Corp., together with its consolidated subsidiaries, FG, NG, FE Aircraft Leasing Corp., Norton Energy Storage L.L.C., and FGMUC, which provides energy-related products and services
FES Debtors	FES and FENOC
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, which is the parent of ATSI, MAIT and TrAIL, and has a joint venture in PATH
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FGMUC	FirstEnergy Generation Mansfield Unit 1 Corp., a wholly owned subsidiary of FG, which has certain leasehold interests in a portion of Unit 1 at the Bruce Mansfield plant
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
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 wholly owned 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
Transmission Companies	ATSI, MAIT and TrAIL
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:

AYE DCD	Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors
AYE Director's Plan	Allegheny Energy, Inc. Non-Employee Director Stock Plan
ACE	Affordable Clean Energy
ADIT	Accumulated Deferred Income Taxes
AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMT	Alternative Minimum Tax
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
ARR	Auction Revenue Right
ASC	Accounting Standard Codification
ASLB	Atomic Safety and Licensing Board
Aspen	Aspen Generating, LLC, a wholly-owned subsidiary of LS Power Equity Partners III, LP
ASU	Accounting Standards Update
Bankruptcy Court	U.S. Bankruptcy Court in the Northern District of Ohio in Akron
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
BV-2	Beaver Valley Unit 2
CAA	Clean Air Act
CBA	Collective Bargaining Agreement
CCR	Coal Combustion Residuals

MGP	Manufactured Gas Plants
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
mmBTU	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOAC	Northwest Ohio Aggregation Coalition
NOL	Net Operating Loss
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission

CDWR	California Department of Water Resources	OCA	Office of Consumer Advocate
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980	OCC	Ohio Consumers' Counsel
CFL	Compact Fluorescent Light	OEPA	Ohio Environmental Protection Agency
CFR	Code of Federal Regulations	OSHA	Occupational Safety and Health Administration
CO2	Carbon Dioxide	OMAEG	Ohio Manufacturers' Association Energy Group
CONE	Cost-of-New-Entry	OPEB	Other Post-Employment Benefits
CPP	EPA's Clean Power Plan	OPEIU	Office and Professional Employees International Union
CSAPR	Cross-State Air Pollution Rule	OPIC	Other Paid-in Capital
CSX	CSX Transportation, Inc.	OTTI	Other-Than-Temporary Impairments
CTA	Consolidated Tax Adjustment	OVEC	Ohio Valley Electric Corporation
CWA	Clean Water Act	PA DEP	Pennsylvania Department of Environmental Protection

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit	PCRB	Pollution Control Revenue Bond
DCPD	Deferred Compensation Plan for Outside Directors	PJM	PJM Interconnection, L.L.C.
DCR	Delivery Capital Recovery	PJM Region	The aggregate of the zones within PJM
DMR	Distribution Modernization Rider	PJM Tariff	PJM Open Access Transmission Tariff
DPM	Distribution Platform Modernization	PM	Particulate Matter
DSIC	Distribution System Improvement Charge	POLR	Provider of Last Resort
DSP	Default Service Plan	POR	Purchase of Receivables
DTA	Deferred Tax Asset	PPA	Purchase Power Agreement
E&P	Earnings and Profits	PPB	Parts per Billion
EDC	Electric Distribution Company	PPUC	Pennsylvania Public Utility Commission
EDCP	Executive Deferred Compensation Plan	PSD	Prevention of Significant Deterioration
EDIS	Electric Distribution Investment Surcharge	PTC	Price-to-Compare
EE&C	Energy Efficiency and Conservation	PUCO	Public Utilities Commission of Ohio
EGS	Electric Generation Supplier	PURPA	Public Utility Regulatory Policies Act of 1978
EGU	Electric Generation Units	R&D	Research and Development
ELPC	Environmental Law & Policy Center	RCRA	Resource Conservation and Recovery Act
EMAAC	Eastern Mid-Atlantic Area Council of PJM	REC	Renewable Energy Credit
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act	Regulation FD	Regulation Fair Disclosure promulgated by the SEC
ENEC	Expanded Net Energy Cost	RFC	ReliabilityFirst Corporation
EPA	United States Environmental Protection Agency	RFP	Request for Proposal
EPRI	Electric Power Research Institute	RGGI	Regional Greenhouse Gas Initiative
EPS	Earnings per Share	RMR	Reliability Must-Run
ERISA	Employee Retirement Income Security Act of 1974	ROE	Return on Equity
ERO	Electric Reliability Organization	RPM	Reliability Pricing Model
ESOP	Employee Stock Ownership Plan	RSS	Rich Site Summary
ESP IV	Electric Security Plan IV	RSU	Restricted Stock Unit
ESTIP	Executive Short-Term Incentive Program	RTEP	Regional Transmission Expansion Plan
Facebook®	Facebook is a registered trademark of Facebook, Inc.	RTO	Regional Transmission Organization
FASB	Financial Accounting Standards Board	RWG	Restructuring Working Group
FERC	Federal Energy Regulatory Commission	S&P	Standard & Poor’s Ratings Service
FE Tomorrow		SAIDI	

	FirstEnergy's initiative launched in late 2016 to identify its optimal organizational structure and properly align corporate costs and systems to efficiently support a fully regulated company going forward		System Average Interruption Duration Index
FES Bankruptcy	FES Debtors' voluntary petitions for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code with the Bankruptcy Court	SAIFI	System Average Interruption Frequency Index
Fitch	Fitch Ratings	SB221	Amended Substitute Senate Bill No. 221
FMB	First Mortgage Bond	SBC	Societal Benefits Charge
FPA	Federal Power Act	SEC	United States Securities and Exchange Commission
FTR	Financial Transmission Right	SERTP	Southeastern Regional Transmission Planning
GAAP	Accounting Principles Generally Accepted in the United States of America	Seventh Circuit	United States Court of Appeals for the Seventh Circuit
GHG	Greenhouse Gases	SF6	Sulfur Hexafluoride
GWH	Gigawatt-hour	SIP	State Implementation Plan(s) Under the Clean Air Act
IBEW	International Brotherhood of Electrical Workers	SO2	Sulfur Dioxide
ICE	Intercontinental Exchange, Inc.	SOS	Standard Offer Service
ICP 2007	FirstEnergy Corp. 2007 Incentive Plan	SPE	Special Purpose Entity
ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan	SRC	Storm Recovery Charge

IIP	Infrastructure Investment Program	SREC	Solar Renewable Energy Credit
IRS	Internal Revenue Service	SSA	Social Security Administration
ISO	Independent System Operator	SSO	Standard Service Offer
JCP&L Reliability Plus	JCP&L Reliability Plus IIP	SVC	Static Var Compensator
kV	Kilovolt	Tax Act	Tax Cuts and Jobs Act adopted December 22, 2017
kW	Kilowatt	TDS	Total Dissolved Solid
KWH	Kilowatt-hour	TMDL	Total Maximum Daily Load
KPI	Key Performance Indicator	TMI-2	Three Mile Island Unit 2
LBR	Little Blue Run	TO	Transmission Owner
LCAPP	Long-Term Capacity Agreement Pilot Program	TTS	Temporary Transaction Surcharge
LED	Light Emitting Diode	Twitter®	Twitter is a registered trademark of Twitter, Inc.
LIBOR	London Interbank Offered Rate	UCC	Official committee of unsecured creditors appointed in connection with the FES Bankruptcy
LMP	Locational Marginal Price	UWUA	Utility Workers Union of America
LOC	Letter of Credit	VEPCO	Virginia Electric and Power Company
LS Power	LS Power Equity Partners III, LP	VIE	Variable Interest Entity
LSE	Load Serving Entity	VRR	Variable Resource Requirement
LTIIPs	Long-Term Infrastructure Improvement Plans	VSCC	Virginia State Corporation Commission
MAAC	Mid-Atlantic Area Council of PJM	WVDEP	West Virginia Department of Environmental Protection
MATS	Mercury and Air Toxics Standards	WVPSC	Public Service Commission of West Virginia
MDPSC	Maryland Public Service Commission		

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, AE Supply, MP, PE, WP, and FET and its principal subsidiaries (ATSI, MAIT and TrAIL). In addition, FE holds all of the outstanding equity of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FELHC, Inc., GPU Nuclear, Inc., AESC and Allegheny Ventures, Inc.

FE and its subsidiaries are principally involved in the transmission, distribution and generation 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. FirstEnergy’s transmission operations include approximately 24,500 miles of lines and two regional transmission operation centers. AGC, JCP&L and MP control 3,790 MWs of total capacity.
FirstEnergy’s revenues are primarily derived from 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).

Regulated 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 the Yard's Creek 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.

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.

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. MP is contractually obligated to provide power to PE to meet its load obligations in West Virginia. MP owns or contractually controls 3,580 MWs of generation capacity that is supplied to its electric utility business, including a 16% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility (487

MWs) and its connecting transmission facilities owned through AGC, which was organized under Virginia law in 1981 and became a wholly owned subsidiary of MP in May 2018.

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.

Regulated Transmission Operating Subsidiaries

ATSI was organized under Ohio law in 1998. ATSI owns 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.

MAIT was organized under Delaware law in 2015. MAIT owns high-voltage transmission facilities, which consist of approximately 4,240 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.

Service Company

FESC provides legal, financial and other corporate support services at cost, in accordance with its cost allocation manual, to affiliated FirstEnergy companies. In addition, pursuant to the FES Bankruptcy settlement agreement discussed below, FE will extend the availability of shared services to the FES Debtors until no later than June 30, 2020, subject to reductions in services if requested by the FES Debtors.

Legacy CES Subsidiaries

On March 31, 2018, FES and FENOC announced that, in order to facilitate an orderly financial restructuring, they filed voluntary petitions under Chapter 11 of the United States Bankruptcy Code with the Bankruptcy Court. As a result of the bankruptcy filings, FirstEnergy concluded that it no longer had a controlling interest in FES and FENOC as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, FES and FENOC were deconsolidated from FirstEnergy's consolidated financial statements. Since such time, FE has accounted and will account for its investments in FES and FENOC at fair values of zero. FE concluded that in connection with the disposal, FES and FENOC became discontinued operations.

AE Supply was organized under Delaware law in 1999. AE Supply previously provided energy-related products and services primarily to wholesale customers. AE Supply also owns and operates the 1,300 MW Pleasants Power Station. As part of the FES Bankruptcy settlement agreement, discussed below, AE Supply will transfer the Pleasants Power Station and related assets to FG, while retaining certain specified liabilities, subject to the terms and conditions of an asset transfer agreement entered into December 31, 2018, which is subject to approval by the Bankruptcy Court. Also, subject to the terms of the asset transfer agreement, FG acquired the economic interests in Pleasants as of January 1, 2019, and AE Supply will operate Pleasants until the transfer.
Substantially all of FirstEnergy's subsidiaries' operations that previously comprised the CES reportable operating segment, including FES, FENOC, BSPC and a portion of AE Supply (including the Pleasants Power Station), are

presented as discontinued operations in FirstEnergy’s consolidated financial statements resulting from the FES Bankruptcy and actions taken as part of the strategic review to exit commodity-exposed generation.

Operating Segments

FirstEnergy's reportable operating segments are comprised of the Regulated Distribution and Regulated Transmission segments.

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. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. Regulation of our retail distribution rates is generally premised on providing an opportunity to earn a reasonable return of and on prudently incurred invested capital to provide service to our customers through the use of both base rate proceedings and other cost-based rate mechanisms, including recovery riders and trackers. The segment's results reflect the costs of securing and delivering electric generation from transmission facilities to customers, including the deferral and amortization of certain related costs.

As of December 31, 2018, FirstEnergy’s regulated generating portfolio consists of 3,790 MWs of diversified capacity 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 the Bath County hydroelectric facility in Virginia that MP partially owns, and 11 MWs of MP's 0.49% entitlement from OVEC's generation output. MP's other generation facilities are located in West Virginia.

The Regulated Transmission segment provides transmission infrastructure owned and operated by the Transmission Companies and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP) to transmit electricity from generation sources to distribution facilities. The segment's revenues are primarily derived from forward-looking formula rates at the Transmission Companies as well as stated transmission rates at JCP&L, MP, PE and WP. Both the forward-looking formula and stated rates recover costs that the regulatory agencies determine are permitted to be recovered and provide a return on transmission capital investment. Under forward-looking formula rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Corporate/Other segment reflects corporate support not charged to FE's subsidiaries, interest expense on FE’s holding company debt and other businesses that do not constitute an operating segment. Additionally, reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are included in Corporate/Other. As of December 31, 2018, approximately 70 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of the Corporate/Other reportable segment. As of December 31, 2018, Corporate/Other had approximately $7.1 billion of FE holding company debt.

On March 31, 2018, as a result of actions taken as part of the strategic review to exit commodity-exposed generation, as discussed below, FirstEnergy deconsolidated FES and FENOC. Also on March 31, 2018, substantially all of FirstEnergy’s operations that previously comprised the CES reportable segment, including FES, FENOC, BSPC and a portion of AE Supply, are presented as discontinued operations in FirstEnergy’s consolidated financial statements. During the third quarter of 2018, the Pleasants Power Station was also reclassified into discontinued operations as a result of the FES Bankruptcy settlement agreement. The financial information for all periods has been revised to present the discontinued operations within Reconciling Adjustments. The remaining business activities that previously comprised the CES reportable operating segment were not material and, as such, have been combined into Corporate/Other for reporting purposes.

Utility Regulation

Regulatory Accounting

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, AGC, and the Transmission Companies 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, and the Transmission Companies 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/credited 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, and the Transmission Companies continue to collect cost-based rates for their transmission and distribution services; accordingly, it is appropriate that the Utilities, AGC, and the Transmission Companies 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 regulatory assets and liabilities are removed from the balance sheet in accordance with GAAP.

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

The following table summarizes the key terms of distribution rate orders in effect for the Utilities.

Company	Rates Effective	Allowed Debt/Equity	Allowed ROE
CEI	May 2009	51% / 49%	10.5%
ME(1)	January 2017	48.8% / 51.2%	Settled(2)
MP	February 2015	54% / 46%	Settled(2)
JCP&L	January 2017	55% / 45%	9.6%
OE	January 2009	51% / 49%	10.5%
PE (West Virginia)	February 2015	54% / 46%	Settled(2)
PE (Maryland)	November 1994	48% / 52%	11.9%
PN(1)	January 2017	47.4% / 52.6%	Settled(2)
Penn(1)	January 2017	49.9% / 50.1%	Settled(2)
TE	January 2009	51% / 49%	10.5%
WP(1)	January 2017	49.7% / 50.3%	Settled(2)

(1) Reflects filed debt/equity as final settlement/orders do not specifically include capital structure.
(2) Commission-approved settlement agreements did not disclose ROE rates.

Federal Regulation

With respect to their wholesale services and rates, the Utilities, AE Supply, and the Transmission Companies 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 JCP&L, MP, PE, WP and the Transmission Companies to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of JCP&L, MP, PE, WP and the Transmission Companies are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under the PJM Tariff. See "FERC Regulatory Matters" below.

The following table summarizes the key terms of rate orders in effect for transmission customer billings for FirstEnergy's transmission owner entities:

Company	Rates Effective	Capital Structure	Allowed ROE
ATSI	January 1, 2015	Actual (13 month average)	10.38%
JCP&L	June 1, 2017	Settled(1)	Settled(1)
MP	March 21, 2018(2)	Settled(1)	Settled(1)
PE	March 21, 2018(2)	Settled(1)	Settled(1)
WP	March 21, 2018(2)	Settled(1)	Settled(1)
MAIT	July 1, 2017	50% / 50% (hypothetical)(3)	10.3%
TrAIL	July 1, 2008	Actual (year-end)	12.7% (TrAIL the Line & Black Oak SVC) 11.7% (All other projects)

(1) FERC-approved settlement agreements did not specify.
(2) See FERC Actions on Tax Act below.
(3) Effective January 2019, converts to lower of actual (13 month average) or 60%.

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

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

Maryland Regulatory Matters

PE operates under MDPSC approved base rates that were effective as of November 11, 1994. PE also 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 EmPOWER Maryland program requires each electric utility to file a plan to reduce electric consumption and demand 0.2% per year, 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. PE's 2016 starting goal under this requirement was 0.97%. PE's approved 2018-2020 EmPOWER Maryland 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. 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.

In 2013, the MDPSC required 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 submitted analysis projected that it would require up to 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 MDPSC's scenarios. The MDPSC conducted a hearing September 2014, but has not taken further action on this matter.

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 in connection with a 2016 MDPSC 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. PE proposed an electric vehicle charging infrastructure program at a projected total cost of $12 million, to be recovered over a five-year amortization. On January 14, 2019, the MDPSC approved the petition subject to certain reductions in the scope of the program.

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. On August 17, 2018, the Staff of the MDPSC filed a reply that recommended the MDPSC instead direct PE to reduce base rates by $6.5 million to reflect reduced federal tax costs pending resolution of PE's upcoming rate case and further direct that PE pay customers a one-time credit for what the Staff estimated were the tax savings to PE through the end of July 2018. On October 5, 2018, the MDPSC issued an order requiring PE to pay a one-time credit for tax savings through September 30, 2018, which totaled approximately $5 million, and reserved all other Tax Act impacts to be resolved in the pending rate case.

On August 24, 2018, PE filed a base rate case with the MDPSC, which it supplemented on October 22, 2018, to update the partially forecasted test year with a full twelve months of actual data. The rate case requested an annual increase in base distribution rates of $19.7 million, plus creation of an EDIS to fund four enhanced service reliability programs. In responding to discovery, PE revised its request for an annual increase in base rates to $17.6 million. The proposed rate increase reflects $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On November 20, 2018, the Staff of the MDPSC filed testimony recommending an increase in base rates of $12.9 million and conditional approval of the EDIS, while the Maryland Office of People's Counsel filed testimony recommending a reduction in rates of $11.1 million and rejection of the EDIS. The evidentiary hearing concluded on January 28, 2019, and a final order is expected by March 23, 2019.

New Jersey Regulatory Matters

JCP&L operates under NJBPU approved rates that were effective as of January 1, 2017. 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. JCP&L 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. 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.

In December 2017, the NJBPU issued proposed rules to modify its current CTA policy in base rate cases to: (i) calculate savings using a five-year look back from the beginning of the test year; (ii) allocate savings with 75% retained by the company and 25% allocated to rate payers; and (iii) exclude transmission assets of electric distribution companies in the savings calculation, which were published in the NJ Register in the first quarter of 2018. JCP&L filed comments supporting the proposed rulemaking. On January 17, 2019, the NJBPU approved the proposed CTA rules with no changes.

Also in December 2017, 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. On July 13, 2018, JCP&L filed an infrastructure plan, JCP&L Reliability Plus, which proposed to accelerate $386.8 million of electric distribution infrastructure investment over four years to enhance the reliability and resiliency of its distribution system and reduce the frequency and duration of power outages. On August 29, 2018, the NJBPU retained the petition for hearing and, on November 22, 2018, issued a procedural schedule. On December 17, 2018, the Division of Rate Counsel recommended a $97 million program, a return on equity of 8.75%, and 5.38% cost of debt. On January 23, 2019, the NJBPU granted JCP&L's request to temporarily suspend procedural schedule in the matter pending settlement discussions. There can be no assurance that a definitive settlement agreement will be reached and, if so, will be approved by the NJBPU.

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. The NJBPU ordered New Jersey utilities to: (1) defer on their books the impacts of the Tax Act effective January 1, 2018; (2) to file tariffs effective April 1, 2018, reflecting the rate impacts of changes in current taxes; and (3) to file tariffs effective July 1, 2018, reflecting the rate impacts of changes in deferred taxes. On March 2, 2018, JCP&L filed a petition with the NJBPU, which included proposed tariffs for a base rate reduction of $28.6 million effective April 1, 2018, and a rider to reflect $1.3 million in rate impacts of changes in deferred taxes. On March 26, 2018, the NJBPU approved JCP&L’s rate reduction effective April 1, 2018, on an interim basis subject to refund, pending the outcome of this proceeding. The NJBPU, however, did not address refunds and other proposed rider tariffs at such time.

Ohio Regulatory Matters

The Ohio Companies currently operate under ESP IV through May 31, 2024. ESP IV includes 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 and is grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. 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. On February 1, 2019, the Ohio Companies filed with the PUCO an application requesting a two-year extension of Rider DMR at the same amount and conditions.

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 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. ESP IV also includes: (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 was filed in February 2016, and remains pending as part of the grid modernization settlement described below; (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 the PUCO denied on

June 13, 2018.

Several parties, including the Ohio Companies, filed applications for rehearing regarding the Ohio Companies' ESP IV with the PUCO. 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. The Ohio Companies then 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, which the PUCO denied. In October 2017, the Sierra Club and the OMAEG filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. The Ohio Companies intervened in the appeal, and additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. On September 26, 2018, the Supreme Court of Ohio denied a July 30, 2018 joint motion filed by the OCC, the NOAC, and the OMAEG to stay the portions of the PUCO's orders and entries under appeal that authorized Rider DMR. Oral argument on the appeals was held on January 9, 2019.

Under Ohio law, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. The Ohio Companies' 2017-2019 plan, as proposed in April 2016, includes 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. In December 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 proposed plans 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. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO's modifications, which the PUCO denied on January

10, 2018. On March 12, 2018, the Ohio Companies appealed to the Supreme Court of Ohio challenging the PUCO's imposition of a 4% cost cap. Various other parties also appealed challenging various PUCO entries on their applications for rehearing. Oral argument on the appeals is scheduled for February 20, 2019.

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, which in 2017 was 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. In August 2013, the PUCO approved the Ohio Companies' REC acquisitions 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. Following appeals, on January 24, 2018, the Supreme Court of Ohio reversed the PUCO order finding that the order violated the rule against retroactive ratemaking. After the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition, on April 25, 2018, the Supreme Court of Ohio denied the motion for reconsideration. As a result, in the second quarter of 2018, the Ohio Companies recognized a pre-tax benefit to earnings (within the Amortization (deferral) of regulatory assets, net line on the Consolidated Statement of Income (Loss)) of approximately $72 million to reverse the liability associated with the PUCO opinion and order.

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. On November 9, 2018, the Ohio Companies filed a settlement agreement that provides for the implementation of the first phase of grid modernization plans, including the investment of $516 million over three years to modernize the Ohio Companies' electric distribution system, and for all tax savings associated with the Tax Act, discussed below, to flow back to customers. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The settlement has broad support, including PUCO Staff, the OCC, representatives of industrial and commercial customers, a low-income advocate, environmental advocates, hospitals, competitive generation suppliers and other parties. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

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, effective January 1, 2018, were required to establish a regulatory liability 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. On October 24, 2018, the PUCO entered an Order in its investigation into the impacts of the Tax Act on Ohio's utilities directing that by January 1, 2019, all Ohio rate-regulated utility companies, unless ordered otherwise, file applications not for an increase in rates to reflect the impact of the Tax Act on each specific utility's current rates. On October 30, 2018, the Ohio Companies filed an application to open a new proceeding for the implementation of matters relating to the impact of the Tax Act. As discussed further above, on November 9, 2018, the Ohio Companies filed a settlement agreement that provides for all tax savings associated with the Tax Act to flow back to customers and for the implementation of the first phase of grid modernization plans. As part of the agreement, the Ohio Companies also filed an application for approval of a rider to return the remaining tax savings to customers following PUCO approval of the settlement. On December 19, 2018, the PUCO upheld its January 10, 2018 ruling that utilities should be required to establish a deferred tax liability, effective

January 1, 2018, in response to the Tax Act. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

Pennsylvania Regulatory Matters

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. 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.

The Pennsylvania Companies' DSPs for the June 1, 2019 through May 31, 2023 delivery period were approved by the PPUC in September 2018. Under the 2019-2023 DSPs, the supply will 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 also include modifications to the Pennsylvania Companies’ POR programs in order to continue their clawback pilot program as a long-term, permanent program term, 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. The PPUC directed a working group to further discuss the implementation of customer assistance program shopping limitations and appropriate scripting for the Pennsylvania Companies' customer referral programs, and in November 2018, issued a subsequent order to approve additional customer assistance program shopping parameters and further limit the scope of the working group discussion. On December 21, 2018, the PPUC issued a tentative order proposing a model to incorporate the directed shopping restrictions. Comments on the proposal were filed January 22, 2019.

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. 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.

Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. LTIIPs outlining infrastructure improvement plans for PPUC review and approval must be filed prior to approval of a DSIC. 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. On September 20, 2018, following a periodic review of the LTIIPs as required by regulation once every five years, the PPUC entered an Order concluding that the Pennsylvania Companies have substantially adhered to the schedules and expenditures outlined in their LTIIPs, but that changes to the LTIIPs as designed are necessary to maintain and improve reliability and directed the Pennsylvania Companies to file modified or new LTIIPs. On January 18, 2019, the Pennsylvania Companies filed modifications to their current LTIIPs that would terminate those LTIIPs at the end of 2019, and proposed revised LTIIP spending in 2019 of $44.52 million by ME, $24.72 million by PN, $26.06 million by Penn and $50.85 million by WP. The Pennsylvania Companies also committed to making filings later in 2019, which would propose new LTIIPs for the 2020 through 2024 period.

The Pennsylvania Companies’ approved DSIC riders for quarterly cost recovery went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. In the January 19, 2017 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. On April 19, 2018, the PPUC approved the Joint Settlement without modification and reversed the ALJ's previous decision that would have required the Pennsylvania Companies to reflect all federal and state income tax deductions related to DSIC-eligible property in currently effective DSIC rates. On May 21, 2018, the Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision of April 19, 2018. On June 11, 2018, the Pennsylvania Companies filed a Notice of Intervention in the Pennsylvania OCA's appeal to the Commonwealth Court. Briefing is complete and oral argument is scheduled for June 3, 2019.

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. On March 9, 2018, the Pennsylvania Companies submitted their calculation of the net annual effect of the Tax Act on income tax expense and rate base to be $37 million for ME, $40 million for PN, $9 million for Penn, and $30 million for WP. The Pennsylvania Companies also filed comments proposing that rates be adjusted to reflect the tax rate changes prospectively from the date of a final PPUC order via a reconcilable rider, with the amount that would otherwise accrue between January 1, 2018 and the date of a final order being used to invest in the Pennsylvania Companies’ infrastructure. On March 15, 2018, the PPUC issued a Temporary Rates Order making the Pennsylvania Companies’ rates temporary and subject to refund for six months. On May 17, 2018, the PPUC issued orders directing that the Pennsylvania Companies implement a reconcilable negative surcharge mechanism in order to refund to customers the net effect of the Tax Act for the period July 1, 2018 through December 31, 2018, to be prospectively updated for new

rates effective January 1, 2019. The Pennsylvania Companies were also directed to establish a regulatory liability for the net impact of the Tax Act for the period of January 1, 2018 through June 30, 2018. On June 14, 2018, the PPUC issued an order revising this directive such that the Pennsylvania Companies must instead establish accounts to track tax savings for the period January 1, 2018 through March 14, 2018, and record regulatory liabilities associated with tax savings for only the period March 15, 2018 through June 30, 2018. The cumulative value of the tracked amounts and the regulatory liability is expected to amount to $12 million for ME, $13 million for PN, $3 million for Penn, and $10 million for WP. These amounts are expected to be addressed in the Pennsylvania Companies' next available rate proceedings, or independent filings to be made within three years, whichever comes sooner. The Pennsylvania Companies filed voluntary surcharges on June 1, 2018, to adjust rates for the reduced tax rate, which were effective for bills rendered starting July 1, 2018. For the first six-month period, the surcharge returned to customers was approximately $22 million for ME, $23 million for PN, $6 million for Penn, and $18 million for WP.
West Virginia Regulatory Matters

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking and operates under rates approved by the WVPSC effective February 2015. 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.

In September 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement, which included 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. 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. This Phase II energy efficiency program ended May 31, 2018.

Previously, AE Supply was the winning bidder of a December 2016 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), subject to customary and other closing conditions, including regulatory approvals. In January 2018, FERC issued an order denying authorization for the transaction and the WVPSC issued an order approving the transfer of Pleasants Power Station conditioned on MP assuming significant commodity risk. Based on the adverse FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement.

On August 31, 2018, MP and PE filed a $100.9 million decrease in their ENEC rates proposed to be effective January 1, 2019, which included a $25.6 million annual decrease impact associated with the settlement regarding the impact of the Tax Act on West Virginia rates, as noted below. Additionally, the August 31, 2018 filing included an elimination of the Energy Efficiency Cost Rate Surcharge effective January 1, 2019, equating to an additional $2.1 million decrease. The rate decreases represent an approximate 7.2% annual decrease in rates versus those in effect on August 31, 2018. A unanimous settlement was filed with the WVPSC on November 20, 2018, and a hearing was held on November 27, 2018. An order adopting the settlement in full without modification was issued on January 2, 2019.

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. 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. MP and PE filed written testimony on May 30, 2018, explaining the impact of the Tax Act on federal income tax and revenue requirements and showing an annual rate impact of $26.2 million. MP and PE, the Staff of the WVPSC, the WV Consumer Advocate and a coalition of industrial customers entered into a settlement agreement on August 23, 2018, to have $25.6 million in rate reductions flow through to customers beginning September 1, 2018, and to defer to the next base rate case (or a separate proceeding if a base rate case is not filed by August 31, 2020) the amount and classification of the excess ADITs resulting from the Tax Act and the issue of whether MP and PE should be required to credit to customers any of the reduced income tax expense occurring between January 1, 2018 and August 31, 2018. The WVPSC approved the settlement on August 24, 2018.

FERC REGULATORY MATTERS

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. With respect to their wholesale services and rates, the Utilities, AE Supply, AGC, and the Transmission Companies are subject to regulation by FERC. FERC regulations require JCP&L, MP, PE, WP and the Transmission Companies to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of JCP&L, MP, PE, WP and the Transmission Companies are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under the PJM Tariff.

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 and AE Supply 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.

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, AE Supply, and the Transmission Companies. 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 the facilities that FirstEnergy operates are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

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

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for a certain class of new transmission facilities since 2005. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocated 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. On May 31, 2018, FERC issued an order approving a settlement agreement among various parties, including ATSI and the Utilities, 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. For historical transmission costs prior to January 1, 2016, the settlement agreement provides a “black-box” schedule of credits to and payments from customers across PJM’s transmission zones. From January 1, 2016 forward, PJM will collect a charge for the revenue requirement associated with each transmission enhancement through a “50/50” calculation, with 50% based on a load-ratio share and the other 50% solution-based distribution factor (DFAX) hybrid method. As a result of the settlement, FirstEnergy recorded a pre-tax benefit of approximately $115 million in 2018 (within the Other operating expenses line on the Consolidated Statement of Income), relating to the amount of refund the Ohio Companies will receive and retain from PJM, of which $73 million is associated with the "black box" calculation of historical transmission costs prior to January 1, 2016, and $42 million is associated with the "50/50" calculation of historical transmission costs from January 1, 2016 to June 30, 2018. PJM implemented the settlement for transmission service in August 2018. Requests for rehearing or clarification of FERC's May 31, 2018, orders and related responses remain pending before FERC. FirstEnergy does not expect a material impact from implementation of the settlement agreement going forward.

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. In a subsequent order, FERC affirmed its prior ruling that ATSI must submit the cost/benefit analysis. ATSI is evaluating the cost/benefit approach.

Separately, 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 September 20, 2018, FERC denied rehearing with respect to its 2016 order regarding allocation of MVP costs and affirmed and clarified its prior decision that MISO may allocate MVP costs to PJM customers for power withdrawals from MISO to PJM as such exports occur.

MAIT Transmission Formula Rate

MAIT previously 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. Following various protests to the proposed MAIT formula transmission rate, 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 May 21, 2018, FERC issued an order accepting a settlement agreement as filed by MAIT and certain parties, without conditions. The settlement agreement provides for certain changes to MAIT's formula rate, including changing MAIT's ROE from 11% to 10.3%, setting the recovery amount for certain regulatory assets, and establishing 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. Refunds for the difference between the filed rate and the settlement rate will be handled through MAIT's true-up process.

JCP&L Transmission Formula Rate

In October 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. Following various protests to the proposed formula transmission rate, 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 February 20, 2018, FERC issued an order accepting a settlement agreement filed by JCP&L and certain parties, with an effective date of June 1, 2017. 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. Refunds for the difference between the filed rate and the settlement rate were paid out ratably in 2018.

FERC Actions on Tax Act

On March 15, 2018, FERC took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FERC directed MP, PE and WP to either submit a joint filing to adjust their stated transmission rates to address the impact of the Tax Act changes in effective tax rate, or to “show cause” as to why such action is not required. FERC established a refund effective date of March 21, 2018, for any refunds as a result of the change in tax rate. On May 14, 2018, MP, PE and WP submitted revisions to their joint stated transmission rate to reflect the reduction in the federal corporate income tax rate. The revisions reduced the stated rate by 6.70%. FERC issued an order on November 15, 2018, accepting the revisions without modifications or conditions.

Also, on March 15, 2018, FERC issued a Notice of Inquiry seeking information regarding whether and how FERC should address possible changes to ADIT and bonus depreciation as a result of the Tax Act. Such possible changes could impact FERC-jurisdictional rates, including transmission rates. On November 15, 2018, FERC issued a NOPR suggesting mechanisms to revise transmission rates to address the Tax Act’s effect on ADIT. Specifically, FERC proposed utilities with transmission formula rates would include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate bases; (ii) raise or lower their income tax allowances by any amortized excess or deficient ADIT; and (iii) incorporate a new permanent worksheet into their rates that will annually track information related to excess or deficient ADIT. Utilities with transmission stated rates would determine the amount of excess and deferred income tax caused by the reduced federal corporate income tax rate and return or recover this amount to or from customers. To assist with implementation of the proposed rule, FERC also issued on November 15, 2018, a policy statement providing accounting and ratemaking guidance for treatment of ADIT for all FERC-jurisdictional public utilities. The policy statement also addresses the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset after December 31, 2017. FESC, on behalf of its affiliated transmission owners, supported comments submitted by Edison Electric Institute requesting additional clarification on the ratemaking and accounting treatment for ADIT in formula and stated transmission rates. FERC's final rule remains pending.

Transmission ROE Methodology

In June 2014, FERC issued Opinion No. 531 revising its approach for calculating the discounted cash flow element of FERC’s ROE methodology and announcing the potential for a qualitative adjustment to the ROE methodology results. Parties appealed to the D.C. Circuit, and on April 14, 2017, that court issued a decision vacating FERC’s order and remanding the matter to FERC for further review. On October 16, 2018, FERC issued its order on remand, in which it proposed a revised ROE methodology. Specifically, in complaint proceedings alleging that an existing ROE is not just and reasonable, FERC proposes to rely on three financial models-discounted cash flow, capital-asset pricing, and expected earnings-to establish a composite zone of reasonableness to identity a range of just and reasonable ROEs. FERC then will utilize the transmission utility’s risk relative to other utilities within that zone of reasonableness to assign the transmission utility to one of three quartiles within the zone. FERC would take no further action (i.e., dismiss the complaint) if the existing ROE falls within the identified quartile. However, if the ROE falls outside the quartile, FERC would deem the existing ROE presumptively unjust and unreasonable and would determine the replacement ROE. FERC would add a fourth financial model risk premium to the analysis to calculate a ROE based on the average point of central tendency for each of the four financial models. FERC established a paper hearing on how the new methodology should apply to the remanded proceedings. FirstEnergy is monitoring the proceedings.

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 participate in dividends paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The preferred shares are convertible at the option of the holders, and will mandatorily convert in July 2019, subject to limited exceptions. Proceeds from the investment were used to reduce FE holding company debt by $1.45 billion and fund FirstEnergy's pension plan as discussed below, with the remainder used for general corporate purposes.

The equity investment is strengthening FirstEnergy's balance sheet and is supporting the company's transition to a fully regulated utility company. By deleveraging the company, the investment also enabled FirstEnergy to enhance its investment grade credit metrics. The January 2018 equity issuance served as a catalyst to FirstEnergy's 2018-2021 "Unlocking the Future" regulated growth plan, which includes earnings growth targets, Regulated Distribution segment average annual rate base growth of 5%, formula transmission average annual rate base growth of 11%, and assumes no additional equity issuances through 2021, outside of FE's regular stock investment and employee benefit plans.

In addition to this equity investment, FE and its distribution 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 2019 and beyond, FE and its distribution 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 distribution 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.

In January 2018, FirstEnergy satisfied its minimum required funding obligations to its qualified pension plan of $500 million and addressed anticipated required funding obligations through 2020 to its pension plan with an additional contribution of $750 million. On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. As a result of this contribution, FirstEnergy expects no required contributions through 2021.
FirstEnergy's capital expenditures for 2019 are expected to be approximately $2.9 to $3.0 billion. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

Capital expenditures for 2018 and forecasted expenditures for 2019, 2020, and 2021, by reportable segment are included below:

Reportable Segment	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast
	(In millions)			
Regulated Distribution	$1,635	$ 1,600 - 1,700	$ 1,500 - 1,700	$ 1,500 - 1,700
Regulated Transmission	1,165	1,200	1,200	1,200
Corporate/Other	183	85	90	110

Total	$2,983	$ 2,885 - 2,985	$ 2,790 - 2,990	$ 2,810 - 3,010

FirstEnergy's transmission growth program, Energizing the Future, provides a stable and proven investment platform, while producing important customer benefits. Through the program, $4.4 billion in capital investments were made from 2014 through 2017, and the company plans to invest up to an additional $4.8 billion in the 2018-2021 timeframe, which includes approximately $1.2 billion in 2018 and a target of $1.2 billion annually through 2021. As noted above, over 80% of these capital investments are recoverable through formula rate mechanisms, reducing regulatory lag in recovering a return on investment, while offering a reasonable rate of return. These investments are expected to continue to improve the performance and condition of the transmission system while increasing automation and communication, adding capacity to the system and improving customer reliability. Beyond 2021, FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of up to approximately $20 billion, 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.

In the Regulated Distribution segment, FirstEnergy remains committed to providing customer service-oriented growth opportunities by investing between $6.2 billion and $6.7 billion over 2018 to 2021, including $1.6 billion invested in 2018. Approximately 40% of capital expenditures are recoverable through various rate mechanisms, riders and trackers. Beginning in 2019, expected investments at the Ohio Companies include the pending Ohio Grid Modernization plan which includes installation of approximately 700,000 advanced meters, distribution automation, and integrated 'volt/var' controls. Additionally, the pending JCP&L Reliability Plus infrastructure improvement plan filed with the NJBPU is expected to bring both reduced outages and strengthen the system while preparing for the grid of the future in New Jersey. FirstEnergy continues to explore other opportunities for growth in its Regulated

Distribution business, 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 electrification of customers' homes and businesses by providing a full range of products and services.

Any financing plans by FE or any of its consolidated subsidiaries, including the issuance of equity and debt, and the refinancing of short-term and maturing long-term debt are subject to market conditions and other factors. No assurance can be given that any such issuances, financing or refinancing, as the case may be, will be completed as anticipated or at all. Any delay in the completion of financing plans could require FE or any of its consolidated subsidiaries to utilize short-term borrowing capacity, which could impact available liquidity. In addition, FE and its consolidated subsidiaries expect to continually evaluate any planned financings, which may result in changes from time to time.

The FES Bankruptcy has also impacted FirstEnergy's capital requirements. On March 9, 2018, FES borrowed $500 million from FE under the secured credit facility, dated as of December 6, 2016, among FES, as Borrower, FG and NG as guarantors, and FE, as lender, which fully utilized the committed line of credit available under the secured credit facility. Following the FES Bankruptcy deconsolidation of FES, FE fully reserved for the $500 million associated with the borrowings under the secured credit facility. Under the terms of the FES Bankruptcy settlement agreement discussed below, FE will release any and all claims against the FES Debtors with respect to the $500 million borrowed under the secured credit facility.

On September 26, 2018, the Bankruptcy Court approved a FES Bankruptcy settlement agreement dated August 26, 2018, by and among FirstEnergy, two groups of key FES creditors (collectively, the FES Key Creditor Groups), the FES Debtors and the UCC. The FES Bankruptcy settlement agreement resolves certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and their creditors against FirstEnergy, and includes the following terms, among others:

- FE will pay certain pre-petition FES and FENOC employee-related obligations, which include unfunded pension obligations and other employee benefits.
- FE will waive all pre-petition claims (other than those claims under the Tax Allocation Agreement for the 2018 tax year) and certain post-petition claims, against the FES Debtors related to the FES Debtors and their businesses, including the full borrowings by FES under the $500 million secured credit facility, the $200 million credit agreement being used to support surety bonds, the BNSF/CSX rail settlement guarantee, and the FES Debtors' unfunded pension obligations.
- The full release of all claims against FirstEnergy by the FES Debtors and their creditors.
- A $225 million cash payment from FirstEnergy.
- A $628 million aggregate principal amount note issuance by FirstEnergy to the FES Debtors, which may be decreased by the amount, if any, of cash paid by FirstEnergy to the FES Debtors under the Intercompany Income Tax Allocation Agreement for the tax benefits related to the sale or deactivation of certain plants.
- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy's Run CCR Impoundment Facility.
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit nine-months of the FES Debtors' shared service costs beginning as of April 1, 2018 through December 31, 2018, in an amount not to exceed $112.5 million, and FirstEnergy agrees to extend the availability of shared services until no later than June 30, 2020.
- FirstEnergy agrees to fund through its pension plan a pension enhancement, subject to a cap, should FES offer a voluntary enhanced retirement package in 2019 and to offer certain other employee benefits.
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FirstEnergy agrees to perform under the Intercompany Tax Allocation Agreement through the FES Debtors' emergence from bankruptcy, at which time FirstEnergy will waive a 2017 overpayment for NOLs of approximately $71 million, reverse 2018 estimated payments for NOLs of approximately $88 million and pay the FES Debtors for the use of NOLs in an amount no less than $66 million for 2018 (of which approximately $52 million has been paid through December 31, 2018).

FirstEnergy determined a loss is probable with respect to the FES Bankruptcy and recorded pre-tax charges totaling $877 million in 2018. See Note 3, "Discontinued Operations," for additional information.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions, most notably the issuance of a final order by the Bankruptcy Court approving the plan or plans of reorganization for the FES Debtors that are acceptable to FirstEnergy consistent with the requirements of the FES Bankruptcy settlement agreement. There can be no assurance that such conditions will be satisfied or the FES Bankruptcy settlement agreement will be otherwise consummated, and the actual outcome of this matter may differ materially from the terms of the agreement described herein. FirstEnergy will continue to evaluate the impact of any new factors on the settlement and their relative impact on the financial statements.

In connection with the FES Bankruptcy settlement agreement, FirstEnergy entered into a separation agreement with the FES Debtors to implement the separation of the FES Debtors and their businesses from FirstEnergy. A business separation committee was established between FirstEnergy and the FES Debtors to review and determine issues that arise in the context of the separation of the FES Debtors' businesses from those of FirstEnergy.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2018, excluding lease commitments, 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.

2019	2020-2023	Total
(In millions)		
$489	$ 3,333	$3,822

The following table displays consolidated operating lease commitments as of December 31, 2018.

Operating Leases	
	(In millions)
2019	$ 34
2020	36
2021	34
2022	30
2023	28
Years thereafter	127
Total minimum lease payments	$ 289

FE and the Utilities, and FET and certain of its subsidiaries, each participate in two separate five-year syndicated revolving credit facilities, which were amended on October 19, 2018, providing for aggregate commitments of $3.5 billion (Facilities), which are available through December 6, 2022. Under the amended FE facility, an aggregate amount of $2.5 billion is available to be borrowed, repaid and reborrowed, subject to separate borrowing sub-limits for each borrower including FE and its regulated distribution subsidiaries. Under the amended FET Facility, an aggregate amount of $1.0 billion is available to be borrowed, repaid and reborrowed under a syndicated credit facility, subject to separate borrowing sub-limits for each borrower including FET and the Transmission Companies. Prior to the amendments to the Facilities, the aggregate commitments under the Facilities was $5.0 billion, which were available until December 6, 2021. FirstEnergy amended the Facilities to reduce costs and to better align FirstEnergy's ongoing liquidity needs with its strategy to be a fully regulated utility company.

Borrowings under the Facilities may be used for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. Generally, borrowings under 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.

On October 19, 2018, FE entered into two separate syndicated term loan credit agreements, the first being a $1.25 billion 364-day facility with The Bank of Nova Scotia, as administrative agent, and the lenders identified therein, and the second being a $500 million two-year facility with JPMorgan Chase Bank, N.A., as administrative agent, and the lenders identified therein, respectively, the proceeds of each were used to reduce short-term debt. The term loans contain covenants and other terms and conditions substantially similar to those of the FE Facility described above, including a consolidated debt-to-total-capitalization ratio.

The initial borrowing of $1.75 billion under the new term loans, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE’s reference ratings plus the highest of (i) the administrative agent's publicly-announced "prime rate", (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE's reference ratings. Changes in FE's reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

FirstEnergy had $1,250 million and $300 million of short-term borrowings as of December 31, 2018 and 2017, respectively. FirstEnergy's available liquidity from external sources as of February 18, 2019, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2022	$2,500	$ 2,490
FET[2]	Revolving	December 2022	1,000	1,000
		Subtotal	3,500	3,490
	Cash and cash equivalents		—	156
		Total	$3,500	$ 3,646

[1] FE and the Utilities. Available liquidity includes impact of $10 million of LOCs issued under various terms.
[2] Includes FET and the Transmission Companies.

Nuclear Regulation

Under NRC regulations, JCP&L, ME and PN must ensure that adequate funds will be available to decommission their retired nuclear facility, TMI-2. As of December 31, 2018, JCP&L, ME and PN had in total approximately $790 million invested in external trusts to be used for the decommissioning and environmental remediation of their retired TMI-2 nuclear generating facility. The values of these NDTs also fluctuate based on market conditions. If the values of the trusts decline by a material amount, the obligation to JCP&L, ME and PN 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.

Nuclear Insurance

JCP&L, ME and PN maintain property damage insurance provided by NEIL for their interest in the retired TMI- 2 nuclear facility, a permanently shut down and defueled facility. Under these arrangements, up to $150 million of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. JCP&L, ME and PN pay annual premiums and are subject to retrospective premium assessments of up to approximately $1.2 million during a policy year.

JCP&L, ME and PN intend to maintain insurance against nuclear risks as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of JCP&L, ME or PN'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 JCP&L, ME or PN's insurance policies, or to the extent such insurance becomes unavailable in the future, JCP&L, ME or PN would remain at risk for such costs.

The Price-Anderson Act limits public liability relative to a single incident at a nuclear power plant. In connection with TMI-2, JCP&L, ME and PN carry the required ANI third party liability coverage and also have coverage under a Price Anderson indemnity agreement issued by the NRC. The total available coverage in the event of a nuclear incident is $560 million, which is also the limit of public liability for any nuclear incident involving TMI-2.

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 materially 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, cash flow 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 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 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 on April 30, 2018, the EPA designated fifty-one areas in twenty-two states as non-attainment; however, FirstEnergy has no power plants operating in those areas. States have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be material and changes to FirstEnergy's 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 sought a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. 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 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition sought NOx emission rate limits for the 36 EGUs by May 1, 2017. On September 14, 2018, the EPA denied both the States of Delaware and Maryland petitions under CAA Section 126. In October 2018, Delaware and Maryland appealed the denials of their petitions to the D.C. Circuit. In March 2018, the State of New York filed a CAA Section 126 petition with the EPA alleging that NOx emissions from nine states (including Ohio, Pennsylvania and West Virginia) significantly contribute to New York's inability to attain the ozone NAAQS. The petition seeks suitable emission rate limits for large stationary sources that are affecting New York's air quality within the three years allowed by CAA Section 126. On May 3, 2018, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to November 9, 2018, but has not taken any further action. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

On May 1, 2017, FE and FG, and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to a coal transportation contract dispute as a result of MATS. Pursuant to the settlement agreement, FG agreed to pay CSX and BNSF an aggregate amount equal to $109 million, 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 provided 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. On April 6, 2018, FE paid the remaining $72 million under the settlement agreement as a result of the FES Bankruptcy.

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. 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 are guaranteed by FE, including the $93 million payment, which was paid in the first quarter of 2018. The parties executed the final settlement agreement on March 9, 2018, and the plaintiff dismissed the matter with prejudice on March 15, 2018.

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. The EPA released its final CPP regulations in August 2015 to reduce CO_2 emissions from existing fossil fuel-fired EGUs and 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. To replace the CPP, the EPA proposed the ACE rule on August 21, 2018, which would establish emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. 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.

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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed all deadlines in the effluent limits rule pending a new rulemaking. On September 18, 2017, the EPA replaced the administrative stay with a rulemaking which postponed only 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 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. March 2018, the WVDEP issued a draft NPDES Permit Renewal that, if finalized as proposed, would moot the appeal and reduce the estimated capital investment requirements. 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. On July 17, 2018, the EPA Administrator signed a final rule extending the deadline for certain CCR facilities to cease disposal and commence closure activities, as well as, establishing less stringent groundwater monitoring and protection requirements. On August 21, 2018, the D.C. Circuit remanded sections of the CCR Rule to the EPA to provide additional safeguards for unlined CCR impoundments that are more protective of human health and the environment. AE Supply assessed the changes in timing and closure plan requirements associated with the McElroy's Run impoundment site and increased the ARO by approximately $43 million in the third quarter of 2018.

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, West Virginia, and the remainder recycled into drywall by National Gypsum. These beneficial reuse options are expected to 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. As noted above, FE provides credit support for FG surety bonds of $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's Ferry disposal site, respectively.

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, 2018, based on estimates of the total costs of cleanup, FirstEnergy's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $121 million have been accrued through December 31, 2018, including approximately $85 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. FE 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

MP currently has coal contracts with various terms to acquire approximately 8.6 million tons of coal for the year 2019, which is approximately 98% of its forecasted 2019 coal requirements. This contracted coal is produced primarily from mines located in Pennsylvania and West Virginia. The contracts expire at various times through 2023. 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.

System Demand

The maximum hourly demand for each of the Utilities was:

System Demand	2018	2017	2016
	(in MWs)		
OE	5,604	5,434	5,655

Penn	950	926	994
CEI	4,301	4,220	4,193
TE	2,367	2,205	2,171
JCP&L	5,977	5,721	5,955
ME	3,026	2,897	2,904
PN	2,993	2,882	2,890
MP	2,089	1,986	2,053
PE	3,498	3,049	3,049
WP	3,879	3,752	3,947

Supply Plan

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 ESP IV), 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.

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.

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. 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 and the Transmission Companies 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 advanced energy and grid applications, reliability improvement for the transmission and distribution system infrastructure, environmental controls, and plant operations and maintenance.

19

Executive Officers as of February 19, 2019

Name	Age	Positions Held During Past Five Years	Dates
S. L. Belcher	50	Senior Vice President and President, FirstEnergy Utilities (B)	2018-present
		President (C) (D) (F)	2018-present
		President, FirstEnergy Nuclear Operating Company (B)	2015-2017
G. D. Benz	59	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	*-2015
D. M. Chack	68	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	54	Senior Vice President, External Affairs (B)	*-present
B. L. Gaines	65	Senior Vice President, Corporate Services and Chief Information Officer (B)	*-present
C. E. Jones	63	President and Chief Executive Officer (A) (B)	2015-present
		President (C) (D)	*-2015
		Executive Vice President & President, FirstEnergy Utilities (A) (B)	2014
C. D. Lasky	56	Senior Vice President, Human Resources and Chief Human Resource Officer (B)	2018-present
		Senior Vice President, Human Resources (B)	2015-2018
		Vice President (E)	*-2015
J. J. Lisowski	37	Vice President, Controller and Chief Accounting Officer (A) (B)	2018-present
		Vice President and Controller (C) (D) (F)	2018-present
E. M. Mikkelsen	58	Vice President, Rates and Regulatory Affairs (B)	2016-present
J. F. Pearson	64	Executive Vice President, Finance (A) (B)	2018-present
		Executive Vice President and Chief Financial Officer (F)	2016-2018
		Executive Vice President and Chief Financial Officer (A) (B) (C) (D)	2015-2018
		Executive Vice President and Chief Financial Officer (E)	2015-2017
		Senior Vice President and Chief Financial Officer (A) (B) (C) (D) (E)	*-2015
I. M. Prezelj	52	Vice President, Investor Relations (B)	*-present
R. P. Reffner	68	Senior Vice President and General Counsel (A) (B) (C) (D) (F)	2018-present
		Vice President and General Counsel (F)	2016-2018
		Vice President and General Counsel (B) (C) (D)	2014-2018
		Vice President and General Counsel (E)	2014-2017
S. E. Strah	54	Senior Vice President and Chief Financial Officer (A) (B) (C) (D) (F)	2018-present

		President (E)	2017-2018
		President (F)	2016-2018
		Senior Vice President & President, FirstEnergy Utilities (B)	2015-2018
		President (C) (D)	2015-2018
		Vice President, Distribution Support (B)	*-2015
L. L. Vespoli	59	Executive Vice President, Corporate Strategy, Regulatory Affairs & Chief Legal Officer (A) (B) (C) (D) (F)	2016-present
		Executive Vice President, Corporate Strategy, Regulatory Affairs & Chief Legal Officer (E)	2016-2017
		Executive Vice President, Markets & Chief Legal Officer (A) (B) (C) (D) (E)	2014-2016
C. L. Walker	53	Vice President, Human Resources (B)	2018-present
E. L. Yeboah-Amankwah	41	Vice President, Deputy General Counsel, Corporate Secretary & Chief Ethics Officer (A) (B)	2018-present
		Vice President, Deputy General Counsel, and Corporate Secretary (C) (D) (E) (F)	2018-present
		Vice President, Corporate Secretary and Chief Ethics Officer (A) (B)	2017-2018
		Vice President and Corporate Secretary (C) (D) (E) (F)	2017-2018
		Vice President, State and Federal Regulatory Legal Affairs (B)	2017

* Indicates position held at least since January 1, 2014

(A) Denotes executive officer of FE

(B) Denotes executive officer of FESC
(C) Denotes executive officer of OE, CEI and TE
(D) Denotes executive officer of ME, PN, Penn, MP, PE, WP, TrAIL, FET, and ATSI

(E) Denotes executive officer of AGC
(F) Denotes executive officer of MAIT

20

Employees

As of December 31, 2018, FirstEnergy had 12,494 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	4,782	899
OE	1,146	765
CEI	916	600
TE	355	264
Penn	183	132
JCP&L	1,364	1,068
ME	659	489
PN	755	478
MP	1,076	716
PE	527	330
WP	731	448
Total	12,494	6,189

As of December 31, 2018, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 5,332 of FirstEnergy's employees. There are 16 CBAs between FirstEnergy's subsidiaries and its unions, which have three, four or five year terms. In 2018, certain of FirstEnergy's subsidiaries reached a new agreement on a CBA with a UWUA local, covering approximately 762 employees. Additionally, in 2018, agreements were reached with two different IBEW locals covering approximately 1,276 employees.

On May 23, 2018 IBEW Local 777CC, which represents approximately 155 employees in the Reading, Pennsylvania, Call Center, ratified a contract that will expire on October 31, 2023. On August 16, 2018 IBEW 1289, which represents approximately 1,114 JCP&L employees, ratified a new agreement that will expire on October 31, 2021. On December 19, 2018, UWUA Local 102, which represents approximately 735 employees in WP and PE ratified a new agreement that will expire on April 30, 2023.

FirstEnergy Web Site and Other Social Media Sites and Applications

FirstEnergy's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports and all other documents filed with or furnished to the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available free of charge on or through the "Investors" page of FirstEnergy’s web site at www.firstenergycorp.com. 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 the web site as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. Additionally, FirstEnergy routinely posts additional important information, including press releases, investor presentations and notices of upcoming events under the "Investors" section of FirstEnergy’s web site and recognizes FirstEnergy’s web site as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of postings to the web site by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's web site. 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 web site, Twitter® handle or Facebook® page, and any corresponding applications of those sites, shall not be deemed incorporated into, or to be part of, this report.

ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. Management regularly evaluates the most significant risks of its businesses and reviews those risks with the Board of Directors or appropriate Committees of the Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we consider material. Additional information on risk factors is included in “Item 1. Business,” “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 FES Bankruptcy

We Are Subject to Risks Relating to the FES Bankruptcy

As previously disclosed, the FES Debtors filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code to facilitate an orderly restructuring. It is possible that as part of the restructuring process, claims may be asserted by or on behalf of the FES Debtors against non-debtor affiliates of the FES Debtors. Any assertions of claims by creditors of the FES Debtors against FirstEnergy may require significant effort, resources, and money to defend or could result in material losses to FirstEnergy. We can provide no assurance that any such claims, if asserted, will be resolved in accordance with the FE Bankruptcy settlement agreement or a manner that is satisfactory to FirstEnergy.

Management of FirstEnergy has been and may continue to be required to spend a significant amount of time and effort dealing with the FES Bankruptcy instead of focusing on FirstEnergy’s business operations, which could have an adverse impact on our ability to execute our business plan and operations. Additionally, FirstEnergy’s relationship with its employees, suppliers, customers and other parties may be adversely impacted by negative or confusing publicity related to the FES Bankruptcy or otherwise and FirstEnergy’s operations could be materially and adversely affected. The FES Bankruptcy also may make it more difficult to retain, attract or replace management and other key personnel.

We are Subject to Risks that the Conditions to the FES Bankruptcy Settlement Agreement May Not be Satisfied or the Settlement May Not Otherwise be Consummated, Which Could Have a Material Adverse Impact on FirstEnergy’s Business, Financial Condition, Results of Operations and Cash Flows

On September 26, 2018, the Bankruptcy Court approved a FES Bankruptcy settlement agreement dated August 26, 2018, by and among FirstEnergy, the FES Key Creditor Groups, the FES Debtors. Under the FES Bankruptcy settlement agreement, FirstEnergy agreed to provide the FES Debtors a release of substantially all claims related to the FES Debtors and their businesses, including for the full borrowings under intercompany financing arrangements and recovery of obligations previously paid under guarantees; payments in the form of cash and new FE notes not to exceed $628 million in aggregate principal amount; the transfer of AE Supply’s Pleasants Power Station; an offsetting credit for shared services costs; funding for certain employee benefit programs; and continued performance under the intercompany tax sharing agreements, including waiver of an FES overpayment, reversal of a payment made for estimated net operating losses and agreement to pay certain 2018 tax year payments. In exchange, the FES Bankruptcy settlement agreement would resolve all outstanding disputes with respect to the claims and causes of action related to the FES Debtors and their businesses among FirstEnergy, on the one hand and the FES Debtors, the FES Key Creditor Groups, and the UCC, on the other hand.

The FES Bankruptcy settlement agreement and the releases granted therein are subject to material conditions, which primarily consist of the issuance of a final order by the Bankruptcy Court approving the plan or plans of reorganization for the FES Debtors acceptable to FirstEnergy. There can be no assurance that the conditions to the settlement agreement will be satisfied or that the settlement will otherwise be consummated, and the actual outcome of this matter may differ materially from the terms of the agreement described herein. If the settlement were not consummated, the FES Debtors or their creditors could assert various claims against FirstEnergy, while FirstEnergy’s

ability to recover any value from obligations owed it by the FES Debtors, secured or otherwise, may be limited.
In the event the FES Bankruptcy settlement agreement is not fully consummated, the costs of potential liabilities resulting from the FES Bankruptcy could have a material and adverse impact on FirstEnergy’s business, financial condition, results of operations and cash flows.

Adverse Developments Related to the FES Bankruptcy 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 of FirstEnergy, 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 the FES Debtors are not “significant subsidiaries” for these purposes, it is possible that an adverse development related to the FES Bankruptcy could otherwise trigger an event of default under the FirstEnergy credit facilities if creditors of the FES Debtors asserted successful claims against FE or our significant subsidiaries.

Certain Events in Connection with the Disposition of Competitive Generation Assets May Significantly Increase Cash Flow and Liquidity Risks and Have a Material Adverse Effect on Results of Operations and the Financial Condition of FirstEnergy

As part of the FES Bankruptcy settlement agreement, AE Supply entered into a definitive agreement on December 31, 2018, to transfer the 1,300 MW Pleasants Power Station and related assets to FG, while retaining certain specified liabilities. After closing, AE Supply will continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred, and FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility. The transfer is subject to various customary and other closing conditions, including the Bankruptcy Court’s approval of the definitive transfer agreement, effectiveness of the FES Bankruptcy settlement agreement and the effectiveness of a plan of reorganization for the FES Debtors in connection with the FES Bankruptcy. Liabilities incurred under these guarantees could have an adverse impact on the financial condition of FirstEnergy.

Further, as part of AE Supply’s 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 the financial condition of FE.

If Our "FE Tomorrow" Organizational Realignment Plans Do Not Achieve the Expected Benefits, There Could Be Negative Impacts to FirstEnergy's Business, Results of Operations and Financial Condition

In support of the strategic review to exit commodity-exposed generation, management launched the FE Tomorrow initiative to define FirstEnergy's future organization to support its regulated business. FE Tomorrow is intended to align corporate services to efficiently support the regulated operations by ensuring that FirstEnergy has the right talent, organizational and cost structure to achieve our earnings growth targets. In support of the FE Tomorrow initiative, in June and early July 2018, nearly 500 employees in the shared services and utility services and sustainability organizations, which was more than 80% of the eligible employees, accepted a voluntary enhanced retirement package, which included severance compensation and a temporary pension enhancement, with most employees retiring by December 31, 2018. Management expects the cost savings resulting from the FE Tomorrow initiative to support the company's growth targets. There can be no assurance that these organizational changes will result in the anticipated benefits to FirstEnergy's business, results of operations and financial condition in a timely manner if at all.

Our ability to achieve the anticipated cost savings and other benefits from FE Tomorrow within the expected time frame is subject to many estimates and assumptions. These estimates and assumptions are subject to significant economic, competitive and other uncertainties, some of which are beyond our control. Further, during and following completion of FE Tomorrow, FirstEnergy could experience unexpected delays in and business disruptions resulting from supporting these initiatives, decreased productivity, higher than anticipated costs, adverse effects on employee morale and employee turnover, including the possible loss of valuable employees, any of which may impair our ability to achieve anticipated results or otherwise harm FirstEnergy's business, results of operations and financial condition.

Risks Associated with Regulation

We Have Taken a Series of Actions to Focus on Growing Our Regulated Distribution and Transmission Operations. 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 Distribution and Transmission operations 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; (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.

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

The Ohio Companies’ Rider DMR provides for the collection of $132.5 million annually for three years through 2019 with a possible extension for an additional two years, which was filed for on February 1, 2019. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2019. Various parties have appealed the PUCO’s denial of subsequent applications for rehearing to the Ohio Supreme Court. On February 1, 2019, the Ohio Companies filed with the PUCO an application requesting a two-year extension of Rider DMR at the same amount and conditions. 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 utility operates. 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, 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 Utilities; (vi) regulatory approval of rate recovery mechanisms for capital spending programs; 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, 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 cost-of-service-based 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 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.

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.

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 AE Supply 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, 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. 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. Various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities' rates and charges. FirstEnergy continues to work with state regulatory commissions to determine appropriate changes to customer rates and, beginning in the first quarter of 2018, began to track and apply regulatory accounting treatment for the expected rate impact of changes in current taxes resulting from the Tax Act. FERC also recently took action to address the impact of the Tax Act on FERC-jurisdictional rates. FirstEnergy has reflected the impact of changes to current taxes in its stated transmission rates and in its normal update to FERC-jurisdictional formula transmission rates and will continue to work with the Commission regarding whether and how FERC should address possible changes to transmission and wholesale rates resulting from the Tax Act.

We cannot predict whether, when or to what extent new tax regulations, interpretations or rulings will be issued, nor is the short-term or long-term impact of the Tax Act clear. Any future 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, further 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.

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. 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.

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 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, 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. 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 Related to Business Operations Generally

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, 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.

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.

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

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies pursuant to transactions involving credit, energy, coal, 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 such non-performance could result in the non-defaulting 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 types described above, legal settlements or under financing transactions. Any failure to perform under such guarantees 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.

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.

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 committed 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 various 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, increased capital and operating costs, litigation or the imposition of penalties/fines or other adverse regulatory outcomes.

Our Use of Non-Derivative and Derivative Contracts 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.

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

We are involved in a number of litigation, arbitration, mediation, and similar proceedings. 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 FirstEnergy could be materially adversely impacted.

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.

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 retired nuclear generating facility and under pension and OPEB 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 retired nuclear generating facility and 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 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 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.

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, including as a result of cybersecurity-related litigation, 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, significant remediation costs, increased regulation, increased capital costs, increased protection costs for enhanced cybersecurity 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.

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. As a result, actual events may lead to greater losses or costs than our risk management positions were intended to hedge.

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

Approximately 86% of FirstEnergy's generation fleet capacity is coal-fired, totaling 3,093 MWs at MP and 1,367 MWs at AE Supply (including 1,300 MWs at Pleasants Power Station which is pending transfer to FG). 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.

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 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 up 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

Traditionally, electricity is generated 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. 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 approximately $190 million at December 31, 2018. 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 debt by $190 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 and transmission 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 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 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

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 remarketing 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. 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, in January 2020 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 preferred shares contain an optional conversion right, and any remaining preferred shares will mandatorily convert in July 2019, subject to limited exceptions.

Upon the conversion of the mandatorily convertible preferred stock, additional shares, up to a maximum of 58,964,222 shares, of our common stock will be issued, which results in dilution to our common 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. As of December 31, 2018, 911,411 shares of preferred stock have been converted into 33,238,910 shares of common stock at the option of the holders. An additional 494,767 preferred shares were converted into 18,044,018 common shares at the option of the holder in January 2019, resulting in 209,822 preferred shares outstanding and yet to be converted as of January 31, 2019.

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 Transaction Occurring as Part of the FES Bankruptcy Will Likely Change the Tax Characterization of Our Distributions to Shareholders

When we make distributions to shareholders, we are required to subsequently determine and report the tax characterization of those distributions for purposes of shareholders’ income taxes. Whether a distribution is characterized as a dividend or a return of capital (and possible capital gain) depends upon an internal tax calculation to determine earnings and profits for income tax purposes (E&P). E&P should not be confused with earnings or net income under GAAP. Further, after we report the expected tax characterization of distributions we have paid, the actual characterization could vary from our expectation with the result that holders of our common stock could incur different income tax liabilities than expected.

In general, distributions are characterized as dividends to the extent the amount of such distributions do not exceed our calculation of current or accumulated E&P. Distributions in excess of current and accumulated E&P may be treated as a non-taxable return of capital. Generally, a non-taxable return of capital will reduce an investor's basis in our stock for federal tax purposes, which will impact the calculation of gain or loss when the stock is sold.

Our internal calculation of E&P can be impacted by a variety of factors. We expect that upon the FES Debtors' emergence from bankruptcy, FirstEnergy's accumulated E&P will be eliminated. All else being equal, eliminating accumulated E&P will make it more likely that at least a portion of our current or future distributions will be characterized for shareholders' tax purposes as a return of capital. Upon such characterization, shareholders are urged to consult their own tax advisors regarding the income tax treatment of our distributions to them.

The Recognition of Impairments of Goodwill and Long-Lived Assets Has Adversely Affected Our Results of Operations and Additional Impairments Could 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, 2018. 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, projected operating income, changes in working capital, projected operating capital expenditures, projected funding of pension plans, expected results of future rate proceedings 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 interest rates, sector market performance, our capital structure, results of future rate proceedings, operating and capital expenditure requirements, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The first mortgage indentures for the Ohio Companies, Penn, MP, PE and WP 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 13, "Capitalization," of the Notes to Consolidated Financial Statements for information concerning financing encumbrances affecting certain of the Utilities' properties.

FirstEnergy controls the following generation sources as of December 31, 2018, shown in the table below. Except for the OVEC participation referenced in the footnotes to the table, the competitive generating units are owned by AE Supply and the regulated generating units are owned by JCP&L and MP.

Plant (Location)	Unit	Total		Competitive	Regulated
		Net Demonstrated Capacity (MW)			
Super-critical Coal-fired:					
Harrison (Haywood, WV)	1-3	1,984		—	1,984
Pleasants (Willow Island, WV)	1-2	1,300	(1)	1,300	—
Fort Martin (Maidsville, WV)	1-2	1,098		—	1,098
		4,382		1,300	3,082
Sub-critical and Other Coal-fired:					
OVEC (Cheshire, OH) (Madison, IN)	1-11	78	(2)	67	11
		78		67	11
Pumped-storage Hydro:					
Bath County (Warm Springs, VA)	1-6	487	(3)	—	487
Yard's Creek (Blairstown Twp., NJ)	1-3	210	(4)	—	210
		697		—	697
Total		5,157		1,367	3,790

(1) On August 26, 2018, FirstEnergy, the FES Key Creditor Groups, the FES Debtors and the UCC entered into a FES Bankruptcy settlement agreement which included the transfer of the Pleasants Power Station and related assets to FES or its designee for the benefit of FES' creditors. Prior to transfer and beginning no later than January 1, 2019, FES acquired the economic interests in Pleasants and AE Supply will operate Pleasants until the transfer.
(2) Represents AE Supply's 3.01% and MP's 0.49% entitlement based on their participation in OVEC.
(3) Represents AGC's 16.25% undivided interest in Bath County. The station is operated by VEPCO.
(4) Represents JCP&L's 50% ownership interest.

The above generating plants and load centers are connected by a transmission system with various voltage ratings ranging from 23 kV to 500 kV. FirstEnergy's overhead and underground transmission lines aggregate 24,506 circuit miles.

The Utilities' electric distribution systems include 277,284 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 164,611,989 kV-amperes.

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

FirstEnergy’s distribution and transmission systems as of December 31, 2018, consist of the following:

	Distribution Lines[(1)]	Transmission Lines[(1)]	Substation Transformer Capacity[(2)] kV Amperes
OE	67,323	379	7,831,823
Penn	13,628	—	1,064,907
CEI	33,528	—	10,100,363
TE	19,088	73	2,892,703
JCP&L	23,666	2,598	23,616,166
ME	19,000	—	5,190,675
PN	27,698	—	9,044,989
ATSI[(3)]	—	7,841	38,651,682
WP	25,014	4,341	15,957,666
MP	22,430	2,650	12,326,155
PE	25,909	2,122	11,256,024
TrAIL	—	262	12,689,600
MAIT	—	4,240	13,989,236
Total	277,284	24,506	164,611,989

(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 16, "Regulatory Matters," and Note 17, "Commitments, Guarantees and Contingencies," of the Notes to Consolidated Financial Statements for a description of certain legal proceedings involving FirstEnergy.

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, dividends and holders of common stock is included in Item 6, "Selected Financial Data."

FirstEnergy had no transactions regarding purchases of FE common stock during the fourth quarter of 2018.

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

ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2018	2017[1]	2016[1]	2015[1]	2014[1]
	(In millions, except per share amounts)				
Revenues	$11,261	$10,928	$10,700	$10,583	$9,455
Income (Loss) From Continuing Operations	$1,022	$(289)	$551	$383	$421
Net Income (Loss) Attributable to Common Stockholders	$981	$(1,724)	$(6,177)	$578	$299
Earnings (Loss) per Share of Common Stock:					
Basic - Continuing Operations	$1.33	$(0.65)	$1.29	$0.91	$1.00
Basic - Discontinued Operations	0.66	(3.23)	(15.78)	0.46	(0.29)
Basic - Net Income (Loss) Attributable to Common Stockholders	$1.99	$(3.88)	$(14.49)	$1.37	$0.71
Diluted - Continuing Operations	$1.33	$(0.65)	$1.29	$0.91	$1.00
Diluted - Discontinued Operations	0.66	(3.23)	(15.78)	0.46	(0.29)
Diluted - Net Income (Loss) Attributable to Common Stockholders	$1.99	$(3.88)	$(14.49)	$1.37	$0.71
Weighted Average Number of Common Shares Outstanding:					
Basic	492	444	426	422	420
Diluted	494	444	426	424	421
Dividends Declared per Share of Common Stock	$1.82	$1.44	$1.44	$1.44	$1.44
As of December 31,					
Total Assets	$40,063	$42,257	$43,148	$52,094	$51,552
Capitalization:					
Total Equity	$6,814	$3,925	$6,241	$12,422	$12,422
Long-Term Debt and Other Long-Term Obligations	17,751	18,687	15,251	16,444	16,345
Total Capitalization	$24,565	$22,612	$21,492	$28,866	$28,767

[1] Prior year numbers have been re-casted for discontinued operations.

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.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2013, 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 74,813 holders of 511,915,450 shares of FE’s common stock as of December 31, 2018, and 74,535 holders of 530,152,175 shares of FE's common stock as of January 31, 2019. Information regarding retained earnings available for payment of cash dividends is given in Note 13, "Capitalization," of the 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 within the meaning of the Private Securities Litigation Reform Act of 1995 based on information currently available. 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, and 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 (see Glossary of Terms for definitions of capitalized terms):

- The ability to successfully execute an exit from commodity-based generation.
- The risks associated with the FES Bankruptcy that could adversely affect us, our liquidity or results of operations, including, without limitation, that conditions to the FES Bankruptcy settlement agreement may not be met or that the FES Bankruptcy settlement agreement may not be otherwise consummated, and if so, the potential for litigation and payment demands against us by FES, FENOC or their creditors.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, our strategy to operate and grow as a fully regulated business, to execute our transmission and distribution investment plans, to continue to reduce costs through FE Tomorrow and other initiatives, and to improve our credit metrics, strengthen our balance sheet and grow earnings.
- Legislative and regulatory developments at the federal and state levels, including, but not limited to, matters related to rates, compliance and enforcement activity.
- Economic and weather conditions affecting future operating results, such as significant weather events and other natural disasters, and associated regulatory events or actions.
- Changes in assumptions regarding economic conditions within our territories, the reliability of our transmission and distribution system, or the availability of capital or other resources supporting identified transmission and distribution investment opportunities.
- Changes in customers' demand for power, including, but not limited to, the impact of state and federal energy efficiency and peak demand reduction mandates.
- Changes in national and regional economic conditions affecting us and/or our major industrial and commercial customers or others with which we do business.
- The risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our operations, and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes to federal and state environmental laws and regulations, including, but not limited to, those related to climate change.
- Changing market conditions affecting the measurement of certain liabilities and the value of assets held in our pension trusts and other trust funds, or causing us to make additional contributions sooner, or in amounts that are larger, than currently anticipated.
- The risks associated with the decommissioning of our retired nuclear facility.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings.
- Labor disruptions by our unionized workforce.
- Changes to significant accounting policies.

- 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.
- Actions that may be taken by credit rating agencies that could negatively affect either our access to or terms of financing or our financial condition and liquidity.
- The risks and other factors discussed from time to time in our SEC filings.

Dividends declared from time to time on our common stock, and thereby on our preferred stock, during any period may in the aggregate vary from prior periods due to circumstances considered by our 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) Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in FirstEnergy's other filings with the SEC. 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 our business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. We expressly disclaim any 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

FE and its subsidiaries are principally involved in the transmission, distribution and generation of electricity through its reportable segments, Regulated Distribution and Regulated Transmission.

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. Regulation of our retail distribution rates is generally premised on providing an opportunity to earn a reasonable return of and on prudently incurred invested capital to provide service to our customers through the use of both base rate proceedings and other cost-based rate mechanisms, including recovery riders and trackers. The segment's results reflect the costs of securing and delivering electric generation from transmission facilities to customers, including the deferral and amortization of certain related costs.

The service areas of, and customers served by, FirstEnergy's regulated distribution utilities as of December 31, 2018 are summarized below (in thousands):

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,051
Penn	Western Pennsylvania	167
CEI	Northeastern Ohio	753
TE	Northwestern Ohio	312
JCP&L	Northern, Western and East Central New Jersey	1,135
ME	Eastern Pennsylvania	572
PN	Western Pennsylvania and Western New York	587
WP	Southwest, South Central and Northern Pennsylvania	727
MP	Northern, Central and Southeastern West Virginia	393
PE	Western Maryland and Eastern West Virginia	414
		6,111

The Regulated Transmission segment provides transmission infrastructure owned and operated by the Transmission Companies and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP) to transmit electricity from generation sources to distribution facilities. The segment's revenues are primarily derived from forward-looking formula rates at the Transmission Companies as well as stated transmission rates at JCP&L, MP, PE and WP. Both the forward-looking formula and stated rates recover costs that the regulatory agencies determine are permitted to be recovered and provide a return on transmission capital investment. Under forward-looking formula rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Corporate/Other segment reflects corporate support not charged to FE's subsidiaries, interest expense on FE’s holding company debt and other businesses that do not constitute an operating segment. Additionally, reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are included in

Corporate/Other. As of December 31, 2018, approximately 70 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of the Corporate/Other reportable segment. As of December 31, 2018, Corporate/Other had approximately $7.1 billion of FE holding company debt.

FES, FENOC, BSPC and a portion of AE Supply (including the Pleasants Power Station), representing substantially all of FirstEnergy’s operations that previously comprised the CES reportable operating segment, are presented as discontinued operations in FirstEnergy’s consolidated financial statements resulting from the FES Bankruptcy and actions taken as part of the strategic review to exit commodity-exposed generation, as discussed below. During the third quarter of 2018, the Pleasants Power Station was reclassified to discontinued operations following its inclusion in the definitive FES Bankruptcy settlement agreement for the benefit of FES' creditors. Prior period results have been reclassified to conform with such presentation as discontinued operations. The financial information for all periods has been revised to present the discontinued operations within Reconciling Adjustments. The remaining business activities that previously comprised the CES reportable operating segment were not material and, as such, have been combined into Corporate/Other for reporting purposes.

EXECUTIVE SUMMARY

FirstEnergy is a forward-thinking electric utility, powered by a diverse team of employees committed to making customers' lives brighter, the environment better and its communities stronger.

Over the past year, FirstEnergy has transformed into a fully regulated utility company, focused on driving sustainable long-term regulated earnings growth and stable cash flows that support its dividend, while also sustaining investment grade credit ratings at FE and its regulated subsidiaries. FirstEnergy believes that the right investments are those that the customers value and are willing to pay for, while also providing attractive returns for its investors.

The scale and diversity of the company’s distribution and transmission operations position FirstEnergy for sustained growth well into the future. Since 2015, the Regulated Distribution business has experienced significant growth through investments, which has been realized through base rates and/or various recovery riders and trackers that have improved reliability and added operating flexibility to distribution infrastructure, benefiting to the customers and communities those Utilities service. The Regulated Transmission business is the centerpiece of FirstEnergy’s regulated investment strategy, where approximately 80% of its capital investments are recovered under forward-looking formula rates for its three standalone Transmission operating companies ATSI, MAIT and TrAIL.

2018-2021 “Unlocking the Future” Plan

The January 2018 equity issuance served as a catalyst to FirstEnergy's 2018-2021 “Unlocking the Future” regulated growth plan, which includes earnings growth targets, Regulated Distribution segment average annual rate base growth of 5%, formula transmission average annual rate base growth of 11%, and assumes no additional equity issuances through 2021, outside of FirstEnergy's regular stock investment and employee benefit plans.

FirstEnergy’s transmission growth program, Energizing the Future, provides a stable and proven investment platform, while producing important customer benefits. Through the program, $4.4 billion in capital investments were made from 2014 through 2017, and the company plans to invest up to an additional $4.8 billion in the 2018-2021 timeframe, which includes approximately $1.2 billion in 2018 and a target of $1.2 billion annually through 2021. As noted above, over 80% of these capital investments are recoverable through formula rate mechanisms, reducing regulatory lag in recovering a return on investment, while offering a reasonable rate of return. These investments are expected to continue to improve the performance and condition of the transmission system while increasing automation and communication, adding capacity to the system and improving customer reliability. Beyond 2021, FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of up to approximately $20 billion, 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.

In the Regulated Distribution segment, FirstEnergy remains committed to providing customer service-oriented growth opportunities by investing between $6.2 billion and $6.7 billion over 2018 to 2021, including $1.6 billion invested in 2018. Approximately 40% of capital expenditures are recoverable through various rate mechanisms, riders and trackers. Beginning in 2019, expected investments at the Ohio Companies include the pending Ohio Grid Modernization plan which includes installation of approximately 700,000 advanced meters, distribution automation, and integrated ‘volt/var’ controls. Additionally, the pending JCP&L Reliability Plus infrastructure improvement plan filed with the NJBPU is expected to bring both reduced outages and strengthen the system while preparing for the grid of the future in New Jersey. FirstEnergy continues to explore other opportunities for growth in its Regulated Distribution business, 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 electrification of customers' homes and businesses by providing a full range of products and services.

Regulated Growth Plans - 2018 Achievements

In addition to our definitive settlement agreement in the FES Bankruptcy, which allowed us to turn our full focus to the implementation of our regulated growth plans in 2018, FirstEnergy made significant progress in positioning the company for sustained and continued regulated growth, including:

- Reached a settlement that is subject to PUCO approval on the Ohio Grid Modernization plan
- Filed a JCP&L Reliability Plus infrastructure investment plan in New Jersey
- Filed a PE distribution rate case in Maryland, the first such base rate filing since 1994
- Announced and implemented a new shared services organizational structure through the FE Tomorrow initiative
- Earned an upgrade from S&P on FE's issuer credit rating to BBB from BBB-
- Earned a positive ratings outlook from Fitch on FE's BBB- credit rating
- Established a Board of Directors approved dividend policy and declared an increased dividend for March 1, 2019
- Implemented rate reductions across all Utilities and at the formula-rate transmission subsidiaries to address the impacts of tax reform to appropriately pass on the benefits to customers

Also in 2018, the FE Tomorrow cost cutting initiative was implemented to define the corporate services FirstEnergy would need to support its regulated business once the company exited commodity-exposed generation. Through the initiative, FirstEnergy sought to ensure the company has the right talent, organizational and cost structure to efficiently service customers and achieve its earnings growth targets. In support of the FE Tomorrow initiative, more than 80% of eligible employees, totaling nearly 500 people in the shared services, utility services and sustainability organizations, accepted a voluntary enhanced retirement package that included severance compensation and a temporary pension enhancement, with most employees having already retired. Management expects the cost savings resulting from the FE Tomorrow initiative to support the company's growth targets.

In November 2018, the Board of Directors approved a dividend policy that includes a targeted payout ratio. As a first step, the Board declared a $0.02 increase to the common dividend payable March 1, 2019 to $0.38 per share, which represents an increase of 6% compared to the quarterly dividend of $0.36 per share that has been paid since 2014. Resuming modest dividend growth enables enhanced shareholder returns, while still allowing for continued substantial regulated investments. Dividend payments are subject to declaration by the Board and future dividend decisions determined by the Board may be impacted by earnings growth, cash flows, credit metrics and other business conditions.

FirstEnergy is making progress in its sustainability efforts. In 2018, FirstEnergy enhanced its focus on sustainability efforts by including the responsibility of Sustainability and Corporate Responsibility oversight into one of the Board’s Charters and created a Sustainability group focused on the continued realization of sustainability accomplishments that make FirstEnergy customers’ lives brighter, the environment better and its communities stronger. These actions reinforce FirstEnergy’s commitment to including the broad concepts of Environmental, Social, Governance (ESG), and corporate responsibility in our sustainability strategy. In 2019, FirstEnergy is focusing on additional initiatives that aim to inform, engage and achieve its sustainability goals, and demonstrate its commitment to stakeholders.

In recognition of customers using electricity in diverse ways, FirstEnergy created an Emerging Technologies department responsible for analyzing and implementing new technologies such as microgrids, plug-in electric vehicles, energy storage, and smart cities. The department will focus on monitoring changing energy policies which support utilities to enable the grid of the future, expanding on sustainable solutions for a better environment, and empowering customers through personalized solutions.

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 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:

	For the Years Ended December 31,			Increase (Decrease)	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$1,242	$916	$651	$326	$265
Regulated Transmission	397	336	331	61	5
Corporate/Other	(617)	(1,541)	(431)	924	(1,110)

Income (Loss) from Continuing Operations	$1,022	$(289)	$551	$1,311	$(840)
Discontinued Operations	326	(1,435)	(6,728)	1,761	5,293
Net Income (Loss)	$1,348	$(1,724)	$(6,177)	$3,072	$4,453
Earnings (Loss) per share of common stock					
Basic - Continuing Operations	$1.33	$(0.65)	$1.29	$1.98	$(1.94)
Basic - Discontinued Operations	0.66	(3.23)	(15.78)	3.89	12.55
Basic - Net Income (Loss) Attributable to Common Stockholders	$1.99	$(3.88)	$(14.49)	$5.87	$10.61
Earnings (Loss) per share of common stock					
Diluted - Continuing Operations	$1.33	$(0.65)	$1.29	$1.98	$(1.94)
Diluted - Discontinued Operations	0.66	(3.23)	(15.78)	3.89	12.55
Diluted - Net Income (Loss) Attributable to Common Stockholders	$1.99	$(3.88)	$(14.49)	$5.87	$10.61

Summary of Results of Operations — 2018 Compared with 2017

Financial results for FirstEnergy's business segments for the years ended December 31, 2018 and 2017, were as follows:

2018 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$9,851	$ 1,335	$ (136)	$ 11,050
Other	252	18	(59)	211
Total Revenues	10,103	1,353	(195)	11,261
Operating Expenses:				
Fuel	538	—	—	538
Purchased power	3,103	—	6	3,109
Other operating expenses	2,984	253	(104)	3,133
Provision for depreciation	812	252	72	1,136
Amortization (deferral) of regulatory assets, net	(163)	13	—	(150)
General taxes	760	192	41	993
Total Operating Expenses	8,034	710	15	8,759
Operating Income (Loss)	2,069	643	(210)	2,502
Other Income (Expense):				
Miscellaneous income (expense), net	192	14	(1)	205
Pension and OPEB mark-to-market adjustment	(109)	(8)	(27)	(144)
Interest expense	(514)	(167)	(435)	(1,116)
Capitalized financing costs	26	37	2	65
Total Other Expense	(405)	(124)	(461)	(990)
Income (Loss) Before Income Taxes (Benefits)	1,664	519	(671)	1,512
Income taxes	422	122	(54)	490
Income (Loss) From Continuing Operations	1,242	397	(617)	1,022
Discontinued Operations, net of tax	—	—	326	326
Net Income (Loss)	$1,242	$ 397	$ (291)	$ 1,348

2017 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$9,521	$ 1,307	$ (94)	$ 10,734
Other	239	17	(62)	194
Total Revenues	9,760	1,324	(156)	10,928
Operating Expenses:				
Fuel	493	—	4	497
Purchased power	2,924	—	2	2,926
Other operating expenses	2,546	203	12	2,761
Provision for depreciation	724	224	79	1,027
Amortization of regulatory assets, net	292	16	—	308
General taxes	727	173	40	940
Impairment of assets	—	41	—	41
Total Operating Expenses	7,706	657	137	8,500
Operating Income (Loss)	2,054	667	(293)	2,428
Other Income (Expense):				
Miscellaneous income (expense), net	57	1	(5)	53
Pension and OPEB mark-to-market adjustment	(102)	—	—	(102)
Interest expense	(535)	(156)	(314)	(1,005)
Capitalized financing costs	22	29	1	52
Total Other Expense	(558)	(126)	(318)	(1,002)
Income (Loss) Before Income Taxes (Benefits)	1,496	541	(611)	1,426
Income taxes (benefits)	580	205	930	1,715
Income (Loss) From Continuing Operations	916	336	(1,541)	(289)
Discontinued Operations, net of tax	—	—	(1,435)	(1,435)
Net Income (Loss)	$916	$ 336	$ (2,976)	$ (1,724)

Changes Between 2018 and 2017 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$330	$ 28	$ (42)	$ 316
Other	13	1	3	17
Total Revenues	343	29	(39)	333
Operating Expenses:				
Fuel	45	—	(4)	41
Purchased power	179	—	4	183
Other operating expenses	438	50	(116)	372
Provision for depreciation	88	28	(7)	109
Amortization (deferral) of regulatory assets, net	(455)	(3)	—	(458)
General taxes	33	19	1	53
Impairment of assets	—	(41)	—	(41)
Total Operating Expenses	328	53	(122)	259
Operating Income	15	(24)	83	74
Other Income (Expense):				
Miscellaneous income (expense), net	135	13	4	152
Pension and OPEB mark-to-market adjustment	(7)	(8)	(27)	(42)
Interest expense	21	(11)	(121)	(111)
Capitalized financing costs	4	8	1	13
Total Other Income (Expense)	153	2	(143)	12
Income (Loss) Before Income Taxes (Benefits)	168	(22)	(60)	86
Income taxes (benefits)	(158)	(83)	(984)	(1,225)
Income (Loss) From Continuing Operations	326	61	924	1,311
Discontinued Operations, net of tax	—	—	1,761	1,761
Net Income (Loss)	$326	$ 61	$ 2,685	$ 3,072

Regulated Distribution — 2018 Compared with 2017

Regulated Distribution's operating results increased $326 million in 2018, as compared to 2017, primarily reflecting the reversal of a reserve on recoverability of certain REC purchases in Ohio, the net impact of a FERC settlement that reallocated certain transmission costs, higher revenues associated with increased weather-related usage and the implementation of approved rates in Ohio and Pennsylvania, as further described below, and lower pension and OPEB non-service costs.

Revenues —

The $343 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2018	2017	Increase
	(In millions)		
Distribution services [1]	$5,413	$5,323	$ 90
Generation sales:			
Retail	3,936	3,733	203
Wholesale	502	465	37
Total generation sales	4,438	4,198	240
Other	252	239	13
Total Revenues	$10,103	$9,760	$ 343

[1] Includes $254 million and $263 million of ARP revenues for the years ended December 31, 2018 and 2017, respectively.

Distribution services revenues increased $90 million primarily resulting from the impact of approved base distribution rate increases in Pennsylvania, effective January 27, 2017, higher revenue from the DCR in Ohio, and higher weather-related customer usage as described below. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs, partially offset by certain tax impacts reflected as a reduction in revenues resulting from the Tax Act. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2018	2017	Increase (Decrease)
	(In thousands)		
Residential	55,994	52,048	7.6 %
Commercial	42,213	41,220	2.4 %
Industrial	53,004	51,876	2.2 %
Other	560	572	(2.1)%
Total Electric Distribution MWH Deliveries	151,771	145,716	4.2 %

Higher distribution deliveries to residential and commercial customers primarily reflect higher weather-related usage resulting from cooling degree days that were 26% above 2017, and 34% above normal, as well as, heating degree days that were 14% above 2017, and 2% 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 $240 million increase in generation revenues in 2018, as compared to 2017:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$ 253
Change in prices	(50)
	203
Wholesale:	
Effect of decrease in sales volumes	(41)
Change in prices	49
Capacity revenue	29
	37
Increase in Generation Revenues	$ 240

The increase in retail generation sales volumes was primarily due to higher weather-related usage, as described above, as well as decreased customer shopping in New Jersey and Pennsylvania. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 50% from 52% in New Jersey and to 67% from 68% in Pennsylvania. The decrease in retail generation prices primarily resulted from lower default service auction prices in New Jersey and Pennsylvania.

Wholesale generation revenues increased $37 million in 2018, as compared to 2017, primarily due to higher spot market energy prices and capacity revenue, partially offset by lower wholesale sales volumes. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery or refund, with no material impact to earnings.

Operating Expenses —

Total operating expenses increased $328 million primarily due to the following:

- Fuel expense increased $45 million in 2018, as compared to 2017, primarily related to higher unit costs.

- Purchased power costs increased $179 million in 2018, as compared to 2017, primarily due to increased volumes resulting from higher customer weather-related usage as well as decreased customer shopping.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (25)
Change due to increased volumes	200
	175
Purchases from affiliates:	
Change due to decreased unit costs	(9)
Change due to decreased volumes	(35)
	(44)

Capacity expense	48
Increase in Purchased Power Costs	$ 179

- Other operating expenses increased $438 million primarily due to:

- Increased storm restoration costs of $228 million, primarily associated with the March 2018 east coast storms, which were mostly deferred for future recovery, resulting in no material impact on current period earnings.
- Higher net network transmission expenses of $49 million reflecting increased transmission costs, partially offset by a FERC settlement during the second quarter of 2018 that reallocated certain transmission costs across utilities in PJM and resulted in a refund to the Ohio Companies. Except for certain transmission costs and credits at the

Ohio Companies, 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 energy efficiency and other program costs of $18 million, which are deferred for future recovery, resulting in no material impact on current period earnings.
- Higher operating and maintenance expenses of $115 million, primarily due to higher benefit costs, increased vegetation management costs and higher contractor spend.
- Pension special termination costs associated with the voluntary retirement program in 2018 of $28 million.

- Depreciation expense increased $88 million, primarily due to a higher asset base.

- Amortization expense decreased $455 million, primarily due to increased deferral of storm restoration costs, the Ohio Supreme Court ruling regarding purchase of RECs, higher deferral of transmission and generation expenses including the net impact of the FERC settlement discussed above, and higher deferral of energy efficiency program costs.

- General taxes expense increased $33 million, primarily due to higher property taxes and revenue-related taxes associated with increased sales volumes.

Other Expense —

Total other expense decreased $153 million, primarily due to higher net miscellaneous income resulting from lower pension and OPEB non-service costs from the pension contribution discussed above, and lower capitalization, as well as lower interest expense resulting from debt maturities and refinancings.

Income Taxes —

Regulated Distribution’s effective tax rate was 25.4% and 38.8% for 2018 and 2017, respectively. The lower rate is primarily a result of certain impacts of the Tax Act and the absence of a $30 million charge to income tax expense as a result of the remeasurement of accumulated deferred income taxes recognized in 2017.

Regulated Transmission — 2018 Compared with 2017

Regulated Transmission's operating results increased $61 million in 2018, as compared to 2017, primarily resulting from the impact of a higher rate base at ATSI and MAIT, higher revenues at JCP&L, and the absence of a pre-tax impairment charge of $41 million in 2017, partially offset by a lower rate base at TrAIL.

Revenues —

Total revenues increased $29 million in 2018, as compared to 2017, primarily due to the full year impact of the implementation of approved settlement rates at JCP&L and recovery of incremental operating expenses and a higher rate base at ATSI and MAIT, partially offset by a lower rate base at TrAIL.

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

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2018	2017	Increase (Decrease)
	(In millions)		
ATSI	$668	$657	$ 11

TrAIL	246	282	(36)
MAIT	154	110	44
Other	285	275	10
Total Revenues	$1,353	$1,324	$ 29

Operating Expenses —

Total operating expenses increased $53 million in 2018, as compared to 2017, primarily due to higher operating and maintenance expenses, as well as higher property taxes and depreciation due to a higher asset base. The majority of the increases are recovered through formula rates at the Transmission Companies, resulting in no material impact on current period earnings. 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.

Income Taxes —

Regulated Transmission’s effective tax rate was 23.5% and 37.9% for 2018 and 2017, respectively. The lower rate is primarily a result of certain impacts of the Tax Act and the absence of a $6 million charge to income tax expense as a result of the remeasurement of accumulated deferred income taxes recognized in 2017.

Corporate/Other — 2018 Compared with 2017

Financial results from the Corporate/Other operating segment and reconciling adjustments resulted in a $924 million increase in income from continuing operations for 2018 compared to 2017, primarily associated with the absence of FES' and FENOC's remeasurement of deferred taxes in 2017, resulting from the Tax Act and lower operating expenses, partially offset by an increase in the ARO at McElroy’s Run, higher interest expense and the 2018 remeasurement of West Virginia unitary group deferred taxes. Although FES' and FENOC's operations are presented in discontinued operations, the 2017 remeasurement of deferred taxes remain in continuing operations in accordance with accounting standards for the impact of tax rate changes. Higher interest expense resulted from FE's issuance of $3 billion of senior notes in June 2017, as well as make-whole premiums of approximately $89 million in connection with the repayment of AE Supply and AGC senior notes in the second quarter of 2018. The increase in taxes resulting from the remeasurement of West Virginia unitary group deferred taxes is primarily due to the legal and financial separation of FES and FENOC from FirstEnergy. This separation officially eroded the ties between FES, FENOC and other FirstEnergy subsidiaries doing business in West Virginia. As such, FES and FENOC were removed from the West Virginia unitary group when calculating West Virginia state income taxes, resulting in a $126 million charge to income tax expense in continuing operations associated with the remeasurement in state deferred taxes.

For the year ended December 31, 2018 and 2017, FirstEnergy recorded income (loss) from discontinued operations, net of tax, of $326 million and $(1,435) million, respectively. Discontinued operations were comprised of the results of FES, FENOC, BSPC and a portion of AE Supply (including the Pleasants Power Station, designated as discontinued operations in the third quarter of 2018) and a net gain on disposal of $435 million in 2018, which consisted of the following:

(In millions)	For the Year Ended December 31, 2018
Removal of investment in FES and FENOC	$ 2,193
Assumption of benefit obligations retained at FE	(820)
Guarantees and credit support provided by FE	(139)
Reserve on receivables and allocated Pension/OPEB mark-to-market	(914)
Settlement consideration and services credit	(1,197)
Loss on disposal of FES and FENOC, before tax	(877)
Income tax benefit, including estimated worthless stock deduction	1,312
Gain on disposal of FES and FENOC, net of tax	$ 435

Summary of Results of Operations — 2017 Compared with 2016

Financial results for FirstEnergy's business segments for the years ended December 31, 2017 and 2016, were as follows:

2017 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$9,521	$ 1,307	$ (94)	$ 10,734
Other	239	17	(62)	194
Total Revenues	9,760	1,324	(156)	10,928
Operating Expenses:				
Fuel	493	—	4	497
Purchased power	2,924	—	2	2,926
Other operating expenses	2,546	203	12	2,761
Provision for depreciation	724	224	79	1,027
Amortization of regulatory assets, net	292	16	—	308
General taxes	727	173	40	940
Impairment of assets	—	41	—	41
Total Operating Expenses	7,706	657	137	8,500
Operating Income (Loss)	2,054	667	(293)	2,428
Other Income (Expense):				
Miscellaneous income (expense), net	57	1	(5)	53
Pension and OPEB mark-to-market adjustment	(102)	—	—	(102)
Interest expense	(535)	(156)	(314)	(1,005)
Capitalized financing costs	22	29	1	52
Total Other Expense	(558)	(126)	(318)	(1,002)
Income (Loss) Before Income Taxes (Benefits)	1,496	541	(611)	1,426
Income taxes (benefits)	580	205	930	1,715
Income (Loss) From Continuing Operations	916	336	(1,541)	(289)
Discontinued Operations, net of tax	—	—	(1,435)	(1,435)
Net Income (Loss)	$916	$ 336	$ (2,976)	$ (1,724)

2016 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$9,352	$ 1,123	$ (12)	$ 10,463
Other	267	20	(50)	237
Total Revenues	9,619	1,143	(62)	10,700
Operating Expenses:				
Fuel	567	—	4	571
Purchased power	3,303	—	7	3,310
Other operating expenses	2,455	152	(28)	2,579
Provision for depreciation	676	187	70	933
Amortization of regulatory assets, net	290	7	—	297
General taxes	720	153	40	913
Impairment of assets	—	—	43	43
Total Operating Expenses	8,011	499	136	8,646
Operating Income (Loss)	1,608	644	(198)	2,054
Other Income (Expense):				
Miscellaneous income (expense), net	85	(1)	(40)	44
Pension and OPEB mark-to-market adjustment	(101)	(1)	—	(102)
Interest expense	(586)	(158)	(229)	(973)
Capitalized financing costs	20	34	1	55
Total Other Expense	(582)	(126)	(268)	(976)
Income (Loss) Before Income Taxes (Benefits)	1,026	518	(466)	1,078
Income taxes (benefits)	375	187	(35)	527
Income (Loss) From Continuing Operations	651	331	(431)	551
Discontinued Operations, net of tax	—	—	(6,728)	(6,728)
Net Income (Loss)	$651	$ 331	$ (7,159)	$ (6,177)

Changes Between 2017 and 2016 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$169	$ 184	$ (82)	$ 271
Other	(28)	(3)	(12)	(43)
Internal	—	—	—	—
Total Revenues	141	181	(94)	228
Operating Expenses:				
Fuel	(74)	—	—	(74)
Purchased power	(379)	—	(5)	(384)
Other operating expenses	91	51	40	182
Provision for depreciation	48	37	9	94
Amortization of regulatory assets, net	2	9	—	11
General taxes	7	20	—	27
Impairment of assets	—	41	(43)	(2)
Total Operating Expenses	(305)	158	1	(146)
Operating Income (Loss)	446	23	(95)	374
Other Income (Expense):				
Miscellaneous income (expense), net	(28)	2	35	9
Pension and OPEB mark-to-market adjustment	(1)	1	—	—
Interest expense	51	2	(85)	(32)
Capitalized financing costs	2	(5)	—	(3)
Total Other Expense	24	—	(50)	(26)
Income (Loss) Before Income Taxes (Benefits)	470	23	(145)	348
Income taxes (benefits)	205	18	965	1,188
Income (Loss) From Continuing Operations	265	5	(1,110)	(840)
Discontinued Operations, net of tax	—	—	5,293	5,293
Net Income (Loss)	$265	$ 5	$ 4,183	$ 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 lower weather-related customer usage, as further described below.

Revenues —

The $141 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 [1]	$5,323	$4,720	$ 603
Generation sales:			
Retail	3,733	4,147	(414)
Wholesale	465	485	(20)
Total generation sales	4,198	4,632	(434)
Other	239	267	(28)
Total Revenues	$9,760	$9,619	$ 141

[1] Includes $263 million and $67 million of ARP revenues for the years ended December 31, 2017 and 2016, respectively.

Distribution services revenues increased $603 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	41,220	42,771	(3.6)%
Industrial	51,876	50,651	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 $434 million decrease in generation revenues in 2017 as compared to 2016:

Source of Change in Generation Revenues	Decrease (In millions)
Retail:	
Effect of decrease in sales volumes	$ (242)
Change in prices	(172)
	(414)
Wholesale:	
Effect of decrease in sales volumes	(6)
Capacity revenue	(14)
	(20)
Decrease in Generation Revenues	$ (434)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania, and JCP&L, 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 $20 million in 2017, as compared to 2016, primarily due to lower capacity revenue and lower 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 $28 million, primarily related to lower transition cost recovery revenues in New Jersey.

Operating Expenses —

Total operating expenses decreased $305 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)

- Other operating expenses increased $91 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 $62 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 $24 million primarily related to lower interest expense resulting from various debt maturities at
JCP&L, CEI and OE, partially offset by the absence of a $29 million gain on the sale of oil and gas rights at WP recognized in 2016.

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.

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

	For the Years Ended December 31,		Increase (Decrease)
Revenues by Transmission Asset Owner	2017	2016	
	(In millions)		
ATSI	$657	$540	$ 117
TrAIL	282	252	30
MAIT[1]	110	101	9
JCPL	125	91	34
Other	150	159	(9)
Total Revenues	$1,324	$1,143	$ 181

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

Operating Expenses —

Total operating expenses increased $158 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.

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.

Corporate/Other — 2017 Compared with 2016

Financial results from the Corporate/Other operating segment and reconciling adjustments resulted in a $1,110 million decrease in income from continuing operations for 2017 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.

For 2017 and 2016, FirstEnergy recorded a loss from discontinued operations, net of tax, of $1,435 million and $6,728 million, respectively. Discontinued operations were comprised of the results of FES, FENOC, BSPC and a portion of AE Supply (including the Pleasants Power Station). Included in these amounts were impairment charges of $2,358 million and $10,622 million for the years ended December 31, 2017 and 2016, respectively.

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, the Utilities and the Transmission Companies 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 federal 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, 2018 and December 31, 2017, and the changes during the year ended December 31, 2018:

Net Regulatory Assets (Liabilities) by Source	December 31, 2018	December 31, 2017	Change
	(In millions)		
Regulatory transition costs	$49	$ 46	$ 3
Customer payables for future income taxes	(2,725)	(2,765)	40
Nuclear decommissioning and spent fuel disposal costs	(148)	(323)	175
Asset removal costs	(787)	(774)	(13)
Deferred transmission costs	170	187	(17)
Deferred generation costs	202	198	4
Deferred distribution costs	208	258	(50)
Contract valuations	62	118	(56)
Storm-related costs	500	329	171
Other	62	46	16
Net Regulatory Liabilities included on the Consolidated Balance Sheets	$(2,407)	$ (2,680)	$ 273

The following is a description of the regulatory assets and liabilities described above:

Regulatory transition costs - Primarily relates to JCP&L costs incurred during the transition to a competitive retail market and under-recovered during the period from August 1, 1999 through July 31, 2003; and JCP&L costs associated with basic generation service, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market. Amounts are amortized through 2021.

Customer payables for future income taxes - Reflects amounts to be recovered or refunded through future rates to pay income taxes that become payable when rate revenue is provided to recover items such as AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes such as tax reform. These amounts are being amortized over the period in which the related deferred tax asset reverse, which is generally over the expected life of the underlying asset. See Note 7, "Taxes" for further discussion on the Tax Act.

Nuclear decommissioning and spent fuel disposal costs - Reflects a regulatory liability representing amounts collected from customers and placed in external trusts including income, losses and changes in fair value thereon (as well as accretion of the related ARO) for the future decommissioning of TMI-2.

Asset removal costs - Primarily represents the rates charged to customers by FirstEnergy's regulated businesses that include a provision for the cost of future activities to remove assets, including obligations for which an asset retirement obligation has been recognized, that are expected to be incurred at the time of retirement.

Deferred transmission costs - Principally represents differences between revenues earned based on actual costs for formula rate companies (the Transmission Companies) and the amounts billed. Amounts are recorded as a regulatory asset or liability and recovered or refunded, respectively, in subsequent periods.

Deferred generation costs - Primarily relates to regulatory assets associated with the securitized recovery of certain electric customer heating discounts, fuel and purchased power regulatory assets at the Ohio Companies (amortized through 2034) as well as the ENEC at MP and PE. 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. The ENEC rate is updated annually.

Deferred distribution costs - Primarily relates to the Ohio Companies deferral of certain expenses resulting from distribution and reliability related expenditures, including interest, and are amortized through 2036.

Contract valuations - Primarily relates to the recovery of Penelec above-market NUG costs. Amounts also include the amortization of a purchase accounting adjustment which was recorded in connection with the AE merger representing the fair value of NUG purchased power contracts (amortized over the life of the contracts with various end dates from 2027 through 2036).

Storm-related costs - Relates to the recovery of storm costs which vary by jurisdiction of which $232 million is currently being recovered through rates. Approximately $268 million is not currently being recovered as of December 31, 2018.

Approximately $503 million and $223 million of regulatory assets, primarily related to storm damage costs, do not earn a current return as of December 31, 2018 and 2017, respectively, and a majority of which are currently being recovered through rates over varying periods depending on the nature of the deferral and the jurisdiction. Additionally, certain regulatory assets, totaling approximately $141 million as of December 31, 2018, are recorded based on prior precedent or anticipated recovery based on rate making premises without a specific order.

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 participate in dividends paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The preferred shares are convertible at the option of the holders, and will mandatorily convert in July 2019, subject to limited exceptions. Proceeds from the investment were used to reduce FE holding company debt by $1.45 billion and fund FirstEnergy's pension plan as discussed below, with the remainder used for general corporate purposes. As of December 31, 2018, 911,411 preferred shares have been converted into 33,238,910 common shares at the option of the holders, resulting in 704,589 shares of preferred shares outstanding. An additional 494,767 preferred shares were converted into 18,044,018 common shares at the option of the holders in January 2019, resulting in 209,822 preferred shares outstanding and yet to be converted as of January 31, 2019.

The equity investment is strengthening FirstEnergy's balance sheet and is supporting the company's transition to a fully regulated utility company. By deleveraging the company, the investment also enabled FirstEnergy to enhance its investment grade credit metrics. The January 2018 equity issuance served as a catalyst to FirstEnergy's 2018-2021 "Unlocking the Future" regulated growth plan, which includes earnings growth targets, Regulated Distribution segment average annual rate base growth of 5%, formula transmission average annual rate base growth of 11%, and assumes no additional equity issuances through 2021, outside of FE's regular stock investment and employee benefit plans.

In addition to this equity investment, FE and its distribution 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 2019 and beyond, FE and its distribution 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 distribution 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.

In January 2018, FirstEnergy satisfied its minimum required funding obligations to its qualified pension plan of $500 million and addressed anticipated required funding obligations through 2020 to its pension plan with an additional contribution of $750 million. On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. As a result of this contribution, FirstEnergy expects no required contributions through 2021.

FirstEnergy's capital expenditures for 2019 are expected to be approximately $2.9 to $3.0 billion. Planned capital initiatives are intended to promote reliability, improve operations, and support current environmental and energy efficiency directives.

Capital expenditures for 2018 and forecasted expenditures for 2019, 2020, and 2021, by reportable segment are included below:

Reportable Segment	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast
	(In millions)			

Regulated Distribution	$1,635	$ 1,600 - 1,700	$ 1,500 - 1,700	$ 1,500 - 1,700
Regulated Transmission	1,165	1,200	1,200	1,200
Corporate/Other	183	85	90	110
Total	$2,983	$ 2,885 - 2,985	$ 2,790 - 2,990	$ 2,810 - 3,010

FirstEnergy's transmission growth program, Energizing the Future, provides a stable and proven investment platform, while producing important customer benefits. Through the program, $4.4 billion in capital investments were made from 2014 through 2017, and the company plans to invest up to an additional $4.8 billion in the 2018-2021 timeframe, which includes approximately $1.2 billion in 2018 and a target of $1.2 billion annually through 2021. As noted above, over 80% of these capital investments are recoverable through formula rate mechanisms, reducing regulatory lag in recovering a return on investment, while offering a reasonable rate of return. These investments are expected to continue to improve the performance and condition of the transmission system while increasing automation and communication, adding capacity to the system and improving customer reliability. Beyond 2021, FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of up to approximately $20 billion, 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.

In the Regulated Distribution segment, FirstEnergy remains committed to providing customer service-oriented growth opportunities by investing between $6.2 billion and $6.7 billion over 2018 to 2021, including $1.6 billion invested in 2018. Approximately 40% of capital expenditures are recoverable through various rate mechanisms, riders and trackers. Beginning in 2019, expected investments at the Ohio Companies include the pending Ohio Grid Modernization plan which includes installation of approximately 700,000 advanced meters, distribution automation, and integrated ‘volt/var’ controls. Additionally, the pending JCP&L Reliability Plus infrastructure improvement plan filed with the NJBPU is expected to bring both reduced outages and strengthen the system while preparing for the grid of the future in New Jersey. FirstEnergy continues to explore other opportunities for growth in its Regulated Distribution business, 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 electrification of customers’ homes and businesses by providing a full range of products and services.

Any financing plans by FE or any of its consolidated subsidiaries, including the issuance of equity and debt, and the refinancing of short-term and maturing long-term debt are subject to market conditions and other factors. No assurance can be given that any such issuances, financing or refinancing, as the case may be, will be completed as anticipated or at all. Any delay in the completion of financing plans could require FE or any of its consolidated subsidiaries to utilize short-term borrowing capacity, which could impact available liquidity. In addition, FE and its consolidated subsidiaries expect to continually evaluate any planned financings, which may result in changes from time to time.

The FES Bankruptcy has also impacted FirstEnergy's capital requirements. On March 9, 2018, FES borrowed $500 million from FE under the secured credit facility, dated as of December 6, 2016, among FES, as Borrower, FG and NG as guarantors, and FE, as lender, which fully utilized the committed line of credit available under the secured credit facility. Following the FES Bankruptcy deconsolidation of FES, FE fully reserved for the $500 million associated with the borrowings under the secured credit facility. Under the terms of the FES Bankruptcy settlement agreement discussed below, FE will release any and all claims against the FES Debtors with respect to the $500 million borrowed under the secured credit facility.

On September 26, 2018, the Bankruptcy Court approved a FES Bankruptcy settlement agreement dated August 26, 2018, by and among FirstEnergy, two groups of key FES creditors (collectively, the FES Key Creditor Groups), the FES Debtors and the UCC. The FES Bankruptcy settlement agreement resolves certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and their creditors against FirstEnergy, and includes the following terms, among others:

- FE will pay certain pre-petition FES and FENOC employee-related obligations, which include unfunded pension obligations and other employee benefits.
- FE will waive all pre-petition claims (other than those claims under the Tax Allocation Agreement for the 2018 tax year) and certain post-petition claims, against the FES Debtors related to the FES Debtors and their businesses, including the full borrowings by FES under the $500 million secured credit facility, the $200 million credit agreement being used to support surety bonds, the BNSF/CSX rail settlement guarantee, and the FES Debtors' unfunded pension obligations.
- The full release of all claims against FirstEnergy by the FES Debtors and their creditors.
- A $225 million cash payment from FirstEnergy.
- A $628 million aggregate principal amount note issuance by FirstEnergy to the FES Debtors, which may be decreased by the amount, if any, of cash paid by FirstEnergy to the FES Debtors under the Intercompany Income Tax Allocation Agreement for the tax benefits related to the sale or deactivation of certain plants.
- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility.
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit nine-months of the FES Debtors' shared service costs beginning as of April 1, 2018 through December 31, 2018, in an amount not to exceed $112.5 million, and FirstEnergy agrees to extend the availability of shared services until no later than

June 30, 2020.

- FirstEnergy agrees to fund through its pension plan a pension enhancement, subject to a cap, should FES offer a voluntary enhanced retirement package in 2019 and to offer certain other employee benefits.
- FirstEnergy agrees to perform under the Intercompany Tax Allocation Agreement through the FES Debtors' emergence from bankruptcy, at which time FirstEnergy will waive a 2017 overpayment for NOLs of approximately $71 million, reverse 2018 estimated payments for NOLs of approximately $88 million and pay the FES Debtors for the use of NOLs in an amount no less than $66 million for 2018 (of which approximately $52 million has been paid through December 31, 2018).

FirstEnergy determined a loss is probable with respect to the FES Bankruptcy and recorded pre-tax charges totaling $877 million in 2018. See Note 3, "Discontinued Operations," for additional information.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions, most notably the issuance of a final order by the Bankruptcy Court approving the plan or plans of reorganization for the FES Debtors that are acceptable to FirstEnergy consistent with the requirements of the FES Bankruptcy settlement agreement. There can be no assurance that such conditions will be satisfied or the FES Bankruptcy settlement agreement will be otherwise consummated, and the actual outcome of this matter may differ materially from the terms of the agreement described herein. FirstEnergy will continue to evaluate the impact of any new factors on the settlement and their relative impact on the financial statements.

In connection with the FES Bankruptcy settlement agreement, FirstEnergy entered into a separation agreement with the FES Debtors to implement the separation of the FES Debtors and their businesses from FirstEnergy. A business separation committee was established between FirstEnergy and the FES Debtors to review and determine issues that arise in the context of the separation of the FES Debtors' businesses from those of FirstEnergy.

In support of the strategic review to exit commodity-exposed generation, management launched the FE Tomorrow cost cutting initiative to define FirstEnergy's future organization to support its regulated business. FE Tomorrow is intended to align corporate services to efficiently support the regulated operations by ensuring that FirstEnergy has the right talent, organizational and cost structure to achieve our earnings growth targets. In support of the FE Tomorrow initiative, in June and early July 2018, nearly 500 employees in the shared services and utility services and sustainability organizations, which was more than 80% of eligible employees, accepted a voluntary enhanced retirement package, which included severance compensation and a temporary pension enhancement, with most employees retiring by December 31, 2018. Management expects the cost savings resulting from the FE Tomorrow initiative to support the company's growth targets.

As of December 31, 2018, FirstEnergy’s 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, 2018, included the following:

Currently Payable Long-Term Debt	December 31, 2018
	(In millions)
Unsecured notes	$ 425
Sinking fund requirements	64
Other notes	14
	$ 503

Short-Term Borrowings / Revolving Credit Facilities

FE and the Utilities, and FET and certain of its subsidiaries, each participate in two separate five-year syndicated revolving credit facilities, which were amended on October 19, 2018, providing for aggregate commitments of $3.5 billion (Facilities), which are available through December 6, 2022. Under the amended FE facility, an aggregate amount of $2.5 billion is available to be borrowed, repaid and reborrowed, subject to separate borrowing sub-limits for each borrower including FE and its regulated distribution subsidiaries. Under the amended FET Facility, an aggregate amount of $1.0 billion is available to be borrowed, repaid and reborrowed under a syndicated credit facility, subject to separate borrowing sub-limits for each borrower including FET and the Transmission Companies. Prior to the amendments to the Facilities, the aggregate commitments under the Facilities was $5.0 billion, which were available until December 6, 2021. FirstEnergy amended the Facilities to reduce costs and to better align FirstEnergy's ongoing liquidity needs with its strategy to be a fully regulated utility company.

Borrowings under the Facilities may be used for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. Generally, borrowings under 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 $1,250 million and $300 million of short-term borrowings as of December 31, 2018 and 2017, respectively. FirstEnergy’s available liquidity from external sources as of February 18, 2019, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	December 2022	$2,500	$ 2,490

FET[2]	Revolving	December 2022	1,000	1,000
		Subtotal	$3,500	$ 3,490
	Cash and cash equivalents		—	156
		Total	$3,500	$ 3,646

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

60

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, 2019:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)			
FE	$2,500	$ —	$ —	(1)
FET	—	1,000	—	(1)
OE	500	—	500	(2)
CEI	500	—	500	(2)
TE	300	—	300	(2)
JCP&L	500	—	500	(2)
ME	500	—	500	(2)
PN	300	—	300	(2)
WP	200	—	200	(2)
MP	500	—	500	(2)
PE	150	—	150	(2)
ATSI	—	500	500	(2)
Penn	100	—	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.

The FE Facility and the FET Facility have $250 million and $100 million, respectively, subject to each borrower's sub-limit, 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, 2018, the borrowers were in compliance with the applicable debt-to-total-capitalization covenants in each case as defined under the respective Facilities. The minimum interest charge coverage ratio no longer applies following FE's upgrade to an investment grade credit rating.

Term Loans

On October 19, 2018, FE entered into two separate syndicated term loan credit agreements, the first being a $1.25 billion 364-day facility with The Bank of Nova Scotia, as administrative agent, and the lenders identified therein, and the second being a $500 million two-year facility with JPMorgan Chase Bank, N.A., as administrative agent, and the lenders identified therein, respectively, the proceeds of each were used to reduce short-term debt. The term loans contain covenants and other terms and conditions substantially similar to those of the FE Facility described above, including a consolidated debt-to-total-capitalization ratio.

The initial borrowing of $1.75 billion under the new term loans, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE’s reference ratings plus the highest of (i) the administrative agent’s publicly-announced “prime rate”, (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE’s reference ratings. Changes in FE’s reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and FE 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. FESC administers these money pools and tracks surplus funds of FE 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 2018 was 2.26% per annum for the regulated companies' money pool and 2.96% per annum for the unregulated companies' money pools.

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 February 19, 2019:

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

Debt capacity is subject to the consolidated debt-to-total-capitalization limits in the credit facilities previously discussed. As of January 31, 2019, FE and its subsidiaries could issue additional debt of approximately $8.8 billion, or incur a $4.7 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, 2018, FirstEnergy had $367 million of cash and cash equivalents and approximately $62 million of restricted cash compared to $589 million of cash and cash equivalents ($1 million in discontinued operations) and approximately $54 million of restricted cash ($3 million in discontinued operations) as of December 31, 2017, on the Consolidated Balance Sheet.

Cash Flows From Operating Activities

FirstEnergy's most significant sources of cash are derived from electric service provided by its distribution and transmission operating subsidiaries. The most significant use of cash from operating activities is buying electricity to serve non-shopping customers and paying fuel suppliers, employees, tax authorities, lenders and others for a wide range of material and services.

FirstEnergy's Consolidated Statement of Cash Flows combines the cash flows from discontinued operations with cash flows from continuing operations within each cash flow statement category. The following table summarized the major classes of cash flow items as discontinued operations for the years ended December 31, 2018, 2017 and 2016:

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income (loss) from discontinued operations	$326	$(1,435)	$(6,728)
Gain on disposal, net of tax	(435)	—	—
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	110	333	669
Deferred income taxes and investment tax credits, net	61	(842)	(3,582)
Unrealized (gain) loss on derivative transactions	(10)	81	9

Net cash provided from operating activities was $1,410 million during 2018, $3,808 million during 2017 and $3,383 million during 2016.

2018 compared with 2017

Cash flows from operations decreased $2,398 million in 2018 as compared with 2017. The year-over-year change in cash from operations decreased due to the following:

- the absence of FES' cash from operations in the last nine months of 2018;
- credit for shared services provided to FES and FENOC during the last nine months of 2018;
- payments of $52 million to FES and FENOC under the intercompany income tax allocation agreement;
- a $1.25 billion cash contribution to the qualified pension plan in 2018;
- a $93 million coal supply agreement dispute settlement payment by AE Supply in the first quarter of 2018;
- a $229 million increase in deferred storm restoration costs;
- a $72 million payment in connection with FE's guarantee of remaining payments on FG's settlement of a coal transportation contract dispute; partially offset by
- higher transmission revenue reflecting recovery of incremental operating expenses, a higher rate base at ATSI and MAIT and the implementation of new rates at JCP&L; and
- higher distribution services retail receipts reflecting higher weather-related usage and the implementation of approved rates in Ohio and Pennsylvania.

2017 compared with 2016

Cash flows from operations increased $425 million in 2017 compared with 2016 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 competitive business capacity revenue and contract sales at Corporate/Other (formerly CES).

63

Cash Flows From Financing Activities

In 2018, cash provided from financing activities was $1,394 million compared to cash used for financing activities of $702 million in 2017 and $34 million in 2016. The following table summarizes new equity and debt financing, redemptions, repayments, short-term borrowings and dividends:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Repaid	2018	2017	2016
	(In millions)		
New Issues			
Preferred stock issuance	$1,616	$—	$—
Common stock issuance	850	—	—
Unsecured notes	850	3,800	—
PCRBs	74	—	471
FMBs	50	625	305
Term loan	500	250	1,200
	$3,940	$4,675	$1,976
Redemptions / Repayments			
Unsecured notes	$(555)	$(1,330)	$(300)
PCRBs	(216)	(158)	(483)
FMBs	(325)	(725)	(246)
Term loan	(1,450)	—	(1,200)
Senior secured notes	(62)	(78)	(102)
	$(2,608)	$(2,291)	$(2,331)
Tender premiums paid on debt redemptions	$(89)	$—	$—
Short-term borrowings (repayments), net	$950	$(2,375)	$975
Preferred stock dividend payments	$(61)	$—	$—
Common stock dividend payments	$(711)	$(639)	$(611)

On January 22, 2018, FE entered into agreements for the private placement of its equity securities representing an approximately $2.5 billion investment in the company, including $1.62 billion in mandatorily convertible preferred equity and $850 million of common equity.

On January 22, 2018, FE repaid $1.2 billion of a variable rate syndicated term loan and two separate $125 million term loans using the proceeds from the $2.5 billion equity investment as discussed above.

On May 3, 2018, AGC redeemed $100 million of 5.06% senior notes due 2021 and paid $5.7 million in related make-whole premiums in connection with the redemption.

On May 10, 2018, MAIT issued $450 million of 4.10% senior notes due 2028. Proceeds from the issuance of the notes were used to establish a capital structure, to finance capital improvements and for general corporate purposes, including funding working capital needs and day-to-day operations.

On June 4, 2018, AE Supply repaid approximately $155 million of 5.75% senior notes due 2019 and approximately $150 million of 6.75% senior notes due 2039, and paid $83.3 million in related make-whole premiums in connection with repayments.

On June 4, 2018, AE Supply and MP caused to be redeemed $73.5 million of 5.50% PCRBs due 2037. On July 10, 2018, such PCRBs were refinanced as MP issued $73.5 million of 3.0% PCRBs with an October 2021 mandatory put.

On June 11, 2018, AE Supply caused to be redeemed $142 million of 5.25% PCRBs due 2037.

On June 15, 2018, JCP&L retired $150 million of 4.8% senior notes at maturity.

On September 27, 2018, ATSI issued $100 million of 4.32% senior notes due 2030. Proceeds were used to refinance existing indebtedness, including amounts under the FE regulated utility money pool, and remaining proceeds will be used to fund working capital needs, and for other general corporate purposes.

On October 3, 2018, Penn issued $50 million of 4.37% first mortgage bonds due 2048. Proceeds were used to refinance existing indebtedness, including amounts under the FE regulated utility money pool, to fund capital expenditures; and for other general corporate purposes.

On October 15, 2018, OE repaid $25 million of 8.25% first mortgage bonds at maturity.

On October 19, 2018, FE entered into a $1.25 billion 364-day term loan due 2019 (classified as short-term borrowings). Proceeds were used for general corporate purposes. Additionally, on October 19, 2018, FE entered into a $500 million two-year variable rate term loan due 2020. Proceeds were used to reduce revolver borrowings.

On November 2, 2018, CEI issued $300 million of 4.55% senior unsecured notes due 2030. Proceeds were used to retire $300 million of 8.875% first mortgage bonds at maturity on November 15, 2018.

On January 10, 2019, ME issued $500 million of 4.30% senior note due 2029. Proceeds from the issuance of senior notes were used to refinance existing indebtedness, including ME's 7.70% senior notes due January 15, 2019, and borrowings outstanding under the FE regulated utility money pool, to fund capital expenditures, and for other general corporate purposes.

On February 8, 2019, JCP&L issued $400 million of 4.30% senior notes due 2026. Proceeds from the issuance of the senior notes were used to refinance existing indebtedness, including amounts under the FE regulated utility money pool incurred in connection with the repayment at maturity of JCP&L's 7.35% senior notes due 2019.

Cash Flows From Investing Activities

Cash used for investing activities in 2018 principally represented cash used for property additions. The following table summarizes investing activities for 2018, 2017 and 2016:

Cash Used for Investing Activities	For the Years Ended December 31, 2018	2017	2016
	(In millions)		
Property Additions:			
Regulated Distribution	$1,411	$1,191	$1,063
Regulated Transmission	1,104	1,030	1,101
Corporate/Other	160	366	671
Nuclear fuel	—	254	232
Proceeds from asset sales	(425)	(388)	(15)
Investments	54	98	111
Notes receivable from affiliated companies	500	—	—
Asset removal costs	218	172	145
Other	(4)	—	(6)
	$3,018	$2,723	$3,302

2018 compared with 2017

Cash used for investing activity in 2018 increased $295 million, as compared to 2017, primarily due to higher property additions and asset removal costs, partially offset by the absence of nuclear fuel purchases and higher proceeds from asset sales. Additionally, the increase in notes receivable from affiliated companies resulted from FES' borrowings from the committed line of credit available under the secured credit facility with FE. The increase in property additions was due to the following:

- an increase of $220 million at Regulated Distribution due to an increase in storm restoration work;
- an increase of $74 million at Regulated Transmission due to timing of capital investments associated with its Energizing the Future investment program; partially offset by,
- a decrease of $206 million at Corporate/Other due to lower competitive generation related investments.

2017 compared with 2016

Cash used for investing activity in 2017 decreased $579 million, compared to 2016, primarily due to lower property additions. The decline in property additions was due to the following:

- a decrease of $305 million at Corporate/Other, resulting from lower competitive generation 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.

CONTRACTUAL OBLIGATIONS

As of December 31, 2018, FirstEnergy's estimated cash payments under existing contractual obligations that it considers firm obligations are as follows:

Contractual Obligations	Total	2019	2020-2021	2022-2023	Thereafter
	(In millions)				
Long-term debt[1]	$18,305	$489	$ 996	$ 2,337	$ 14,483
Short-term borrowings	1,250	1,250	—	—	—
Interest on long-term debt[2]	11,307	850	1,632	1,487	7,338
Operating leases[3]	289	34	70	58	127
Capital leases[3]	96	24	35	21	16
Fuel and purchased power[4]	5,102	877	1,261	1,139	1,825
Capital expenditures [5]	1,841	576	905	360	—
Pension funding [6]	1,951	500	—	837	614
Total	$40,141	$4,600	$ 4,899	$ 6,239	$ 24,403

(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, 2018.
(3) See Note 8, "Leases," of the 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, 2018.
(6) 2019 reflects voluntary cash contribution made to the qualified pension plan on February 1, 2019.

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 $2.6 billion in 2019.

The table above also excludes regulatory liabilities (see Note 16, "Regulatory Matters"), AROs (see Note 15, "Asset Retirement Obligations"), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 17, "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

JCP&L, ME and PN maintain property damage insurance provided by NEIL for their interest in the retired TMI- 2 nuclear facility, a permanently shut down and defueled facility. Under these arrangements, up to $150 million of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. JCP&L, ME and PN pay annual premiums and are subject to retrospective premium assessments of up to approximately $1.2 million during a policy year.

JCP&L, ME and PN intend to maintain insurance against nuclear risks as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of JCP&L, ME or PN’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 JCP&L, ME or PN’s insurance policies, or to the extent such insurance becomes unavailable in the future, JCP&L, ME or PN would remain at risk for such costs.

The Price-Anderson Act limits public liability relative to a single incident at a nuclear power plant. In connection with TMI-2, JCP&L, ME and PN carry the required ANI third party liability coverage and also have coverage under a Price Anderson indemnity agreement issued by the NRC. The total available coverage in the event of a nuclear incident is $560 million, which is also the limit of public liability for any nuclear incident involving TMI-2.

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, 2018, was approximately $1.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FE's Guarantees on Behalf of FES and FENOC	
Energy and Energy-Related Contracts[1]	$ 5
Surety Bonds - FG[2]	200
Deferred compensation arrangements	140
	345
FE's Guarantees on Behalf of its Consolidated Subsidiaries	
AE Supply asset sales[3]	555
Deferred compensation arrangements	423
Fuel related contracts and other	21
	999
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	190
Other Assurances	
Surety Bonds	130
LOCs[4]	10
	140
Total Guarantees and Other Assurances	$ 1,674

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy. As of December 31, 2018, FE recorded an obligation for these guarantees in other non-current liabilities with a corresponding loss from discontinued operations.

(2) 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 CCR impoundment closure and post-closure activities and the Hatfield's Ferry CCR disposal site, respectively.

(3) As a condition to closing AE Supply's sale of four natural gas generating plants in December 2017, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC. In connection with the FES Bankruptcy settlement agreement, FirstEnergy has also committed to provide certain additional guarantees to FG for retained environmental liabilities of AE Supply related to the Pleasants Power Station and the McElroy's Run CCR disposal facility.

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

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 AE Supply's power portfolio exposure as of December 31, 2018, AE Supply has posted no collateral. The Utilities and Transmission Companies have posted collateral totaling $2 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, 2018:

Potential Collateral Obligations	AE Supply	Utilities and FET	FE	Total
	(In millions)			
Contractual Obligations for Additional Collateral				
At Current Credit Rating	$1	$ —	$—	$1
Upon Further Downgrade	—	62	—	62
Surety Bonds (Collateralized Amount)[1]	1	59	246	306
Total Exposure from Contractual Obligations	$2	$ 121	$246	$369

[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 CCR impoundment closure and post-closure activities and the Hatfield's Ferry CCR disposal site, respectively.

Other Commitments and Contingencies

FE is a guarantor under a $300 million syndicated senior secured term loan facility due March 3, 2020, under which Global Holding's outstanding principal balance is $190 million as of December 31, 2018. 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.

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 has limited exposure to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice.

The valuation of derivative contracts is based on observable market information. As of December 31, 2018, FirstEnergy has a net liability of $44 million in non-hedge derivative contracts that are primarily related to NUG contracts at certain of the Utilities. NUG contracts are subject to regulatory accounting and do not impact earnings.

Equity Price Risk

As of December 31, 2018, the FirstEnergy pension plan assets were allocated approximately as follows: 36% in equity securities, 34% in fixed income securities, 11% in absolute return strategies, 10% in real estate, 2% in private equity, 2% in derivatives and 5% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. In January 2018, FirstEnergy satisfied its minimum required funding obligations to its qualified pension plan of $500 million and addressed anticipated required funding obligations through 2020 to its pension plan with an additional contribution of $750 million. On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. As a result of this contribution, FirstEnergy expects no required contributions through 2021. See Note 5, "Pension and Other Postemployment Benefits," of the Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension and OPEB plans. Through December 31, 2018, FirstEnergy's pension plan assets had losses of approximately (4.2)% as compared to an annual expected return on plan assets of 7.5%.

As of December 31, 2018, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through December 31, 2018, FirstEnergy's OPEB plans have earned approximately (1.0)% as compared to an annual expected return on plan assets of 7.5%.

NDT funds have been established to satisfy JCP&L, ME and PN's nuclear decommissioning obligations associated with TMI-2. As of December 31, 2018, approximately 55% of the funds were invested in fixed income securities, 43% of the funds were invested in equity securities and 2% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $438 million, $338 million and $13 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2018, excluding $(1) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $34 million reduction in fair value as of December 31, 2018. A decline in the value of JCP&L, ME and PN's NDTs or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2018, JCP&L, ME and PN 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.

Comparison of Carrying Value to Fair Value

Year of Maturity	2019	2020	2021	2022	2023	There-after	Total	Fair Value
	(In millions)							
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$—	$—	$—	$—	$—	$688	$688	$688
Average interest rate	— %	— %	— %	— %	— %	3.1 %	3.1 %	
Liabilities:								
Long-term Debt:								
Fixed rate	$489	$364	$58	$1,100	$1,150	$14,654	$17,815	$18,766
Average interest rate	6.7 %	5.4 %	4.7 %	4.1 %	4.2 %	5.0 %	4.9 %	
Variable rate	$—	$500	$—	$—	$—	$—	$500	$500
Average interest rate	— %	3.3 %	— %	— %	— %	— %	3.3 %	

CREDIT RISK

Credit risk is the risk that FirstEnergy would incur a loss as a result of nonperformance by counterparties of their contractual obligations. FirstEnergy maintains credit policies and procedures with respect to counterparty credit (including requirement that counterparties maintain specified credit ratings) and require other assurances in the form of credit support or collateral in certain circumstance in order to limit counterparty credit risk. However, FirstEnergy, as applicable, has concentrations of suppliers and customers among electric utilities, financial institutions and energy marketing and trading companies. These concentrations may impact FirstEnergy's overall exposure to credit risk, positively or negatively, as counterparties may be similarly affected by changes in economic, regulatory or other conditions. In the event an energy supplier of the Ohio Companies, Pennsylvania Companies, JCP&L or PE defaults on its obligation, the Ohio Companies, Pennsylvania Companies, JCP&L and PE would be required to seek replacement power in the market. In general, subject to regulatory review or other processes, appropriate incremental costs incurred by these entities would be recoverable from customers through applicable rate mechanisms, thereby mitigating the financial risk for these entities. FirstEnergy's credit policies to manage credit risk include the use of an established credit approval process, daily credit mitigation provisions, such as margin, prepayment or collateral requirements. FirstEnergy and its subsidiaries may request additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade, their tangible net worth falls below specified percentages or their exposures exceed an established credit limit.

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

The following table summarizes the key terms of distribution rate orders in effect for the Utilities.

Company	Rates Effective	Allowed Debt/Equity	Allowed ROE
CEI	May 2009	51% / 49%	10.5%
ME[1]	January 2017	48.8% / 51.2%	Settled[2]
MP	February 2015	54% / 46%	Settled[2]
JCP&L	January 2017	55% / 45%	9.6%
OE	January 2009	51% / 49%	10.5%
PE-West Virginia	February 2015	54% / 46%	Settled[2]
PE-Maryland	November 1994	48% / 52%	11.9%
PN[1]	January 2017	47.4% / 52.6%	Settled[2]
Penn[1]	January 2017	49.9% / 50.1%	Settled[2]
TE	January 2009	51% / 49%	10.5%
WP[1]	January 2017	49.7% / 50.3%	Settled[2]

[1] Reflects filed debt/equity as final settlement/orders do not specifically include capital structure.
[2] Commission-approved settlement agreements did not disclose ROE rates.

MARYLAND

PE operates under MDPSC approved base rates that were effective as of November 11, 1994. PE also 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 EmPOWER Maryland program requires each electric utility to file a plan to reduce electric consumption and demand 0.2% per year, 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. PE's 2016 starting goal under this requirement was 0.97%. PE's approved 2018-2020 EmPOWER Maryland 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. 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.

In 2013, the MDPSC required 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 submitted analysis projected that it would require up to 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 MDPSC's scenarios. The MDPSC conducted a hearing September 2014, but has not taken further action on this matter.

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 in connection with a 2016 MDPSC 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. PE proposed an electric vehicle charging infrastructure program at a projected total cost of $12 million, to be recovered over a five-year amortization. On January 14, 2019, the MDPSC approved the petition subject to certain reductions in the scope of the program.

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. On August 17, 2018, the Staff of the MDPSC filed a reply that recommended the MDPSC instead direct PE to reduce base rates by $6.5 million to reflect reduced federal tax costs pending resolution of PE's upcoming rate case and further direct that PE pay customers a one-time credit for what the Staff estimated were the tax savings to PE through the end of July 2018. On October 5, 2018, the MDPSC issued an order requiring PE to pay a one-time credit for tax savings through September 30, 2018, which totaled approximately $5 million, and reserved all other Tax Act impacts to be resolved in the pending rate case.

On August 24, 2018, PE filed a base rate case with the MDPSC, which it supplemented on October 22, 2018, to update the partially forecasted test year with a full twelve months of actual data. The rate case requested an annual increase in base distribution rates of $19.7 million, plus creation of an EDIS to fund four enhanced service reliability programs. In responding to discovery, PE revised its request for an annual increase in base rates to $17.6 million. The proposed rate increase reflects $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On November 20, 2018, the Staff of the MDPSC filed testimony recommending an increase in base rates of $12.9 million and conditional approval of the EDIS, while the Maryland Office of People's Counsel filed testimony recommending a reduction in rates of $11.1 million and rejection of the EDIS. The evidentiary hearing concluded on January 28, 2019, and a final order is expected by March 23, 2019.

NEW JERSEY

JCP&L operates under NJBPU approved rates that were effective as of January 1, 2017. 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. JCP&L 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. 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.

In December 2017, the NJBPU issued proposed rules to modify its current CTA policy in base rate cases to: (i) calculate savings using a five-year look back from the beginning of the test year; (ii) allocate savings with 75% retained by the company and 25% allocated to rate payers; and (iii) exclude transmission assets of electric distribution companies in the savings calculation, which were published in the NJ Register in the first quarter of 2018. JCP&L filed comments supporting the proposed rulemaking. On January 17, 2019, the NJBPU approved the proposed CTA rules with no changes.

Also in December 2017, 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. On July 13, 2018, JCP&L filed an infrastructure plan, JCP&L Reliability Plus, which proposed to accelerate $386.8 million of electric distribution infrastructure investment over four years to enhance the reliability and resiliency of its distribution system and reduce the frequency and duration of power outages. On August 29, 2018, the NJBPU retained the petition for hearing and, on November 22, 2018, issued a procedural schedule. On December 17, 2018, the Division of Rate Counsel recommended a $97 million program, a return on equity of 8.75%, and 5.38% cost of debt. On January 23, 2019, the NJBPU granted JCP&L's request to temporarily suspend procedural schedule in the matter pending settlement discussions. There can be no assurance that a definitive settlement agreement will be reached and, if so, will be approved by the NJBPU.

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. The NJBPU ordered New Jersey utilities to: (1) defer on their books the impacts of the Tax Act effective January 1, 2018; (2) to file tariffs effective April 1, 2018, reflecting the rate impacts of changes in current taxes; and (3) to file tariffs effective July 1, 2018, reflecting the rate impacts of changes in deferred taxes. On March 2, 2018, JCP&L filed a petition with the NJBPU, which included proposed tariffs for a base rate reduction of $28.6 million effective April 1, 2018, and a rider to reflect $1.3 million in rate impacts of changes in deferred taxes. On March 26, 2018, the NJBPU approved JCP&L's rate reduction effective April 1, 2018, on an interim basis subject to refund, pending the outcome of this proceeding. The NJBPU, however, did not address refunds and other proposed rider tariffs at such time.

OHIO

The Ohio Companies currently operate under ESP IV through May 31, 2024. ESP IV includes 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 and is grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. 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. On February 1, 2019, the Ohio Companies filed with the PUCO an application requesting a two-year extension of Rider DMR at the same amount and conditions.

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 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. ESP IV also includes: (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 was filed in February 2016, and remains pending as part of the grid modernization settlement described below; (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 the PUCO denied on June 13, 2018.

Several parties, including the Ohio Companies, filed applications for rehearing regarding the Ohio Companies' ESP IV with the PUCO. 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. The Ohio Companies then 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, which the PUCO denied. In October 2017, the Sierra Club and the OMAEG filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. The Ohio Companies intervened in the appeal, and additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. On September 26, 2018, the Supreme Court of Ohio denied a July 30, 2018 joint motion filed by the OCC, the NOAC, and the OMAEG to stay the portions of the PUCO's orders and entries under appeal that authorized Rider DMR. Oral argument on the appeals was held on January 9, 2019.

Under Ohio law, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. The Ohio Companies' 2017-2019 plan, as proposed in April 2016, includes 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. In December 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 proposed plans 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. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO's modifications, which the PUCO denied on January 10, 2018. On March 12, 2018, the Ohio Companies appealed to the Supreme Court of Ohio challenging the PUCO's imposition of a 4% cost cap. Various other parties also appealed challenging various PUCO entries on their applications for rehearing. Oral argument on the appeals is scheduled for February 20, 2019.

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, which in 2017 was 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. In August 2013, the PUCO approved the Ohio Companies' REC acquisitions 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. Following appeals, on January 24, 2018, the Supreme Court of Ohio reversed the PUCO order finding that the order violated the rule against retroactive ratemaking. After the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition, on April 25, 2018, the Supreme Court of Ohio denied the motion for reconsideration. As a result, in the second quarter of 2018, the Ohio Companies recognized a pre-tax benefit to earnings (within the Amortization (deferral) of regulatory assets, net line on the Consolidated Statement of Income (Loss)) of approximately $72 million to reverse the liability associated with the PUCO opinion and order.

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. On November 9, 2018, the Ohio Companies filed a settlement agreement that provides for the implementation of the first phase of grid modernization plans, including the investment of $516 million over three years to modernize the Ohio Companies’ electric distribution system, and for all tax savings associated with the Tax Act, discussed below, to flow back to customers. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The settlement has broad support, including PUCO Staff, the OCC, representatives of industrial and commercial customers, a low-income advocate, environmental advocates, hospitals, competitive generation suppliers and other parties. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

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, effective January 1, 2018, were required to establish a regulatory liability 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. On October 24, 2018, the PUCO entered an Order in its investigation into the impacts of the Tax Act on Ohio's utilities directing that by January 1, 2019, all Ohio rate-regulated utility companies, unless ordered otherwise, file applications not for an increase in rates to reflect the impact of the Tax Act on each specific utility's current rates. On October 30, 2018, the Ohio Companies filed an application to open a new proceeding for the implementation of matters relating to the impact of the Tax Act. As discussed further above, on November 9, 2018, the Ohio Companies filed a settlement agreement that provides for all tax savings associated with the Tax Act to flow back to customers and for the implementation of the first phase of grid modernization plans. As part of the agreement, the Ohio Companies also filed an application for approval of a rider to return the remaining tax savings to customers following PUCO approval of the settlement. On December 19, 2018, the PUCO upheld its January 10, 2018 ruling that utilities should be required to establish a deferred tax liability, effective January 1, 2018, in response to the Tax Act. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

PENNSYLVANIA

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. 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.

The Pennsylvania Companies' DSPs for the June 1, 2019 through May 31, 2023 delivery period were approved by the PPUC in September 2018. Under the 2019-2023 DSPs, the supply will 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 also include modifications to the Pennsylvania Companies’ POR programs in order to continue their clawback pilot program as a long-term, permanent program term, 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. The PPUC directed a working group to further discuss the implementation of customer assistance program shopping limitations and appropriate scripting for the Pennsylvania Companies' customer referral programs, and in November 2018, issued a subsequent order to approve additional customer assistance program shopping parameters and further limit the scope of the working group discussion. On December 21, 2018, the PPUC issued a tentative order proposing a model to incorporate the directed shopping restrictions. Comments on the proposal were filed January 22, 2019.

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. 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.

Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. LTIIPs outlining infrastructure improvement plans for PPUC review and approval must be filed prior to approval of a DSIC. 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. On September 20, 2018, following a periodic review of the LTIIPs as required by regulation once every five years, the PPUC entered an Order concluding that the Pennsylvania Companies have substantially adhered to the schedules and expenditures outlined in their LTIIPs, but that changes to the LTIIPs as designed are necessary to maintain and improve reliability and directed the Pennsylvania Companies to file modified or new LTIIPs. On January 18, 2019, the Pennsylvania Companies filed modifications to their current LTIIPs that would terminate those LTIIPs at the end of 2019, and proposed revised LTIIP spending in 2019 of $44.52 million by ME, $24.72 million by PN, $26.06 million by Penn and $50.85 million by WP. The Pennsylvania Companies also committed to making filings later in 2019, which would propose new LTIIPs for the 2020 through 2024 period.

The Pennsylvania Companies’ approved DSIC riders for quarterly cost recovery went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. In the January 19, 2017 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. On April 19, 2018, the PPUC approved the Joint Settlement without modification and reversed the ALJ's previous decision that would have required the Pennsylvania Companies to reflect all federal and state income tax deductions related to DSIC-eligible property in currently effective DSIC rates. On May 21, 2018, the Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision of April 19, 2018. On June 11, 2018, the Pennsylvania Companies filed a Notice of Intervention in the Pennsylvania OCA's appeal to the Commonwealth Court. Briefing is complete and oral argument is scheduled for June 3, 2019.

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. On March 9, 2018, the Pennsylvania Companies submitted their calculation of the net annual effect of the Tax Act on income tax expense and rate base to be $37 million for ME, $40 million for PN, $9 million for Penn, and $30 million for WP. The Pennsylvania Companies also filed comments proposing that rates be adjusted to reflect the tax rate changes prospectively from the date of a final PPUC order via a reconcilable rider, with the amount that would otherwise accrue between January 1, 2018 and the date of a final order being used to invest in the Pennsylvania Companies’ infrastructure. On March 15, 2018, the PPUC issued a Temporary Rates Order making the Pennsylvania Companies’ rates temporary and subject to refund for six months. On May 17, 2018, the PPUC issued orders directing that the Pennsylvania Companies implement a reconcilable negative surcharge mechanism in order to refund to customers the net effect of the Tax Act for the period July 1, 2018 through December 31, 2018, to be prospectively updated for new rates effective January 1, 2019. The Pennsylvania Companies were also directed to establish a regulatory liability for the net impact of the Tax Act for the period of January 1, 2018 through June 30, 2018. On June 14, 2018, the PPUC issued an order revising this directive such that the Pennsylvania Companies must instead establish accounts to track tax savings for the period January 1, 2018 through March 14, 2018, and record regulatory liabilities associated with tax savings for only the period March 15, 2018 through June 30, 2018. The cumulative value of the tracked amounts and the regulatory liability is expected to amount to $12 million for ME, $13 million for PN, $3 million for Penn, and $10 million for WP. These amounts are expected to be addressed in the Pennsylvania Companies' next available rate proceedings, or independent filings to be made within three years, whichever comes sooner. The Pennsylvania Companies filed voluntary surcharges on June 1, 2018, to adjust rates for the reduced tax rate, which were effective for bills rendered starting July 1, 2018. For the first six-month period, the surcharge returned to customers was approximately $22 million for ME, $23 million for PN, $6 million for Penn, and $18 million for WP.

WEST VIRGINIA

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking and operates under rates approved by the WVPSC effective February 2015. 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.

In September 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement, which included 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. 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. This Phase II energy efficiency program ended May 31, 2018.

Previously, AE Supply was the winning bidder of a December 2016 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), subject to customary and other closing conditions, including regulatory approvals. In January 2018, FERC issued an order denying authorization for the transaction and the WVPSC issued an order approving the transfer of Pleasants Power Station conditioned on MP assuming significant commodity risk. Based on the adverse FERC ruling and the conditions included in the WVPSC order, MP and AE Supply terminated the asset purchase agreement.

On August 31, 2018, MP and PE filed a $100.9 million decrease in their ENEC rates proposed to be effective January 1, 2019, which included a $25.6 million annual decrease impact associated with the settlement regarding the impact of the Tax Act on West Virginia rates, as noted below. Additionally, the August 31, 2018 filing included an elimination of the Energy Efficiency Cost Rate Surcharge effective January 1, 2019, equating to an additional $2.1 million decrease. The rate decreases represent an approximate 7.2% annual decrease in rates versus those in effect on August 31, 2018. A unanimous settlement was filed with the WVPSC on November 20, 2018, and a hearing was held on November 27, 2018. An order adopting the settlement in full without modification was issued on January 2, 2019.

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. 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. MP and PE filed written testimony on May 30, 2018, explaining the impact of the Tax Act on federal income tax and revenue requirements and showing an annual rate impact of $26.2 million. MP and PE, the Staff of the WVPSC, the WV Consumer Advocate and a coalition of industrial customers entered into a settlement agreement on August 23, 2018, to have $25.6 million in rate reductions flow through to customers beginning September 1, 2018, and to defer to the next base rate case (or a separate proceeding if a base rate case is not filed by August 31, 2020) the amount and classification of the excess ADITs resulting from the Tax Act and the issue of whether MP and PE should be required to credit to customers any of the reduced income tax expense occurring between January 1, 2018 and August 31, 2018. The WVPSC approved the settlement on August 24, 2018.

FERC REGULATORY MATTERS

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. With respect to their wholesale services and rates, the Utilities, AE Supply, AGC, and the Transmission Companies are subject to regulation by FERC. FERC regulations require JCP&L, MP, PE, WP and the Transmission Companies to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of JCP&L, MP, PE, WP and the Transmission Companies are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under the PJM Tariff.

The following table summarizes the key terms of rate orders in effect for transmission customer billings for FirstEnergy's transmission owner entities:

Company	Rates Effective	Capital Structure	Allowed ROE
ATSI	January 1, 2015	Actual (13 month average)	10.38%
JCP&L	June 1, 2017	Settled(1)	Settled(1)
MP	March 21, 2018(2)	Settled(1)	Settled(1)
PE	March 21, 2018(2)	Settled(1)	Settled(1)
WP	March 21, 2018(2)	Settled(1)	Settled(1)
MAIT	July 1, 2017	50% / 50% (hypothetical)(3)	10.3%
TrAIL	July 1, 2008	Actual (year-end)	12.7% (TrAIL the Line & Black Oak SVC) 11.7% (All other projects)

(1) FERC-approved settlement agreements did not specify.
(2) See FERC Actions on Tax Act below.
(3) Effective January 2019, converts to lower of actual (13 month average) or 60%.

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 and AE Supply 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.

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, AE Supply, and the Transmission Companies. 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 the facilities that FirstEnergy operates are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

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

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for a certain class of new transmission facilities since 2005. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocated 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. On May 31, 2018, FERC issued an order approving a settlement agreement among various parties, including ATSI and the Utilities, 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. For historical transmission costs prior to January 1, 2016, the settlement agreement provides a “black-box” schedule of credits to and payments from customers across PJM’s transmission zones. From January 1, 2016 forward, PJM will collect a charge for the revenue requirement associated with each transmission enhancement through a “50/50” calculation, with 50% based on a load-ratio share and the other 50% solution-based distribution factor (DFAX) hybrid method. As a result of the settlement, FirstEnergy recorded a pre-tax benefit of approximately $115 million in 2018 (within the Other operating expenses line on the Consolidated Statement of Income), relating to the amount of refund the Ohio Companies will receive and retain from PJM, of which $73 million is associated with the "black box" calculation of historical transmission costs prior to January 1, 2016, and $42 million is associated with the "50/50" calculation of historical transmission costs from January 1, 2016 to June 30, 2018. PJM implemented the settlement for transmission service in August 2018. Requests for rehearing or clarification of FERC's May 31, 2018, orders and related responses remain pending before FERC. FirstEnergy does not expect a material impact from implementation of the settlement agreement going forward.

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. In a subsequent order, FERC affirmed its prior ruling that ATSI must submit the cost/benefit analysis. ATSI is evaluating the cost/benefit approach.

Separately, 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 September 20, 2018, FERC denied rehearing with respect to its 2016 order regarding allocation of MVP costs and affirmed and clarified its prior decision that MISO may allocate MVP costs to PJM customers for power withdrawals from MISO to PJM as such exports occur.

MAIT Transmission Formula Rate

MAIT previously 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. Following various protests to the proposed MAIT formula transmission rate, 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 May 21, 2018, FERC issued an order accepting a settlement agreement as filed by MAIT and certain parties, without conditions. The settlement agreement provides for certain changes to MAIT's formula rate, including changing MAIT's ROE from 11% to 10.3%, setting the recovery amount for certain regulatory assets, and establishing 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. Refunds for the difference between the filed rate and the settlement rate will be handled through MAIT's true-up process.

JCP&L Transmission Formula Rate

In October 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. Following various protests to the proposed formula transmission rate, 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 February 20, 2018, FERC issued an order accepting a settlement agreement filed by JCP&L and certain parties, with an effective date of June 1, 2017. 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. Refunds for the difference between the filed rate and the settlement rate were paid out ratably in 2018.

FERC Actions on Tax Act

On March 15, 2018, FERC took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FERC directed MP, PE and WP to either submit a joint filing to adjust their stated transmission rates to address the impact of the Tax Act changes in effective tax rate, or to “show cause” as to why such action is not required. FERC established a refund effective date of March 21, 2018, for any refunds as a result of the change in tax rate. On May 14, 2018, MP, PE and WP submitted revisions to their joint stated transmission rate to reflect the reduction in the federal corporate income tax rate. The revisions reduced the stated rate by 6.70%. FERC issued an order on November 15, 2018, accepting the revisions without modifications or conditions.

Also, on March 15, 2018, FERC issued a Notice of Inquiry seeking information regarding whether and how FERC should address possible changes to ADIT and bonus depreciation as a result of the Tax Act. Such possible changes could impact FERC-jurisdictional rates, including transmission rates. On November 15, 2018, FERC issued a NOPR suggesting mechanisms to revise transmission rates to address the Tax Act’s effect on ADIT. Specifically, FERC proposed utilities with transmission formula rates would include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate bases; (ii) raise or lower their income tax allowances by any amortized excess or deficient ADIT; and (iii) incorporate a new permanent worksheet into their rates that will annually track information related to excess or deficient ADIT. Utilities with transmission stated rates would determine the amount of excess and deferred income tax caused by the reduced federal corporate income tax rate and return or recover this amount to or from customers. To assist with implementation of the proposed rule, FERC also issued on November 15, 2018, a policy statement providing accounting and ratemaking guidance for treatment of ADIT for all FERC-jurisdictional public utilities. The policy statement also addresses the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset after December 31,

2017. FESC, on behalf of its affiliated transmission owners, supported comments submitted by Edison Electric Institute requesting additional clarification on the ratemaking and accounting treatment for ADIT in formula and stated transmission rates. FERC's final rule remains pending.

Transmission ROE Methodology

In June 2014, FERC issued Opinion No. 531 revising its approach for calculating the discounted cash flow element of FERC’s ROE methodology and announcing the potential for a qualitative adjustment to the ROE methodology results. Parties appealed to the D.C. Circuit, and on April 14, 2017, that court issued a decision vacating FERC’s order and remanding the matter to FERC for further review. On October 16, 2018, FERC issued its order on remand, in which it proposed a revised ROE methodology. Specifically, in complaint proceedings alleging that an existing ROE is not just and reasonable, FERC proposes to rely on three financial models-discounted cash flow, capital-asset pricing, and expected earnings-to establish a composite zone of reasonableness to identity a range of just and reasonable ROEs. FERC then will utilize the transmission utility’s risk relative to other utilities within that zone of reasonableness to assign the transmission utility to one of three quartiles within the zone. FERC would take no further action (i.e., dismiss the complaint) if the existing ROE falls within the identified quartile. However, if the ROE falls outside the quartile, FERC would deem the existing ROE presumptively unjust and unreasonable and would determine the replacement ROE. FERC would add a fourth financial model risk premium to the analysis to calculate a ROE based on the average point of central tendency for each of the four financial models. FERC established a paper hearing on how the new methodology should apply to the remanded proceedings. FirstEnergy is monitoring the proceedings.

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 materially 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, cash flow 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 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 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 on April 30, 2018, the EPA designated fifty-one areas in twenty-two states as non-attainment; however, FirstEnergy has no power plants operating in those areas. States have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be material and changes to FirstEnergy's 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 sought a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. 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 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition sought NOx emission rate limits for the 36 EGUs by May 1, 2017. On September 14, 2018, the EPA denied both the States of Delaware and Maryland petitions under CAA Section 126.

In October 2018, Delaware and Maryland appealed the denials of their petitions to the D.C. Circuit. In March 2018, the State of New York filed a CAA Section 126 petition with the EPA alleging that NOx emissions from nine states (including Ohio, Pennsylvania and West Virginia) significantly contribute to New York's inability to attain the ozone NAAQS. The petition seeks suitable emission rate limits for large stationary sources that are affecting New York's air quality within the three years allowed by CAA Section 126. On May 3, 2018, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to November 9, 2018, but has not taken any further action. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

On May 1, 2017, FE and FG, and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to a coal transportation contract dispute as a result of MATS. Pursuant to the settlement agreement, FG agreed to pay CSX and BNSF an aggregate amount equal to $109 million, 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 provided 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. On April 6, 2018, FE paid the remaining $72 million under the settlement agreement as a result of the FES Bankruptcy.

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. 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 are guaranteed by FE, including the $93 million payment, which was paid in the first quarter of 2018. The parties executed the final settlement agreement on March 9, 2018, and the plaintiff dismissed the matter with prejudice on March 15, 2018.

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. The EPA released its final CPP regulations in August 2015 to reduce CO_2 emissions from existing fossil fuel-fired EGUs and 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. To replace the CPP, the

EPA proposed the ACE rule on August 21, 2018, which would establish emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. 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.

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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed all deadlines in the effluent limits rule pending a new rulemaking. On September 18, 2017, the EPA replaced the administrative stay with a rulemaking which postponed only 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 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. March 2018, the WVDEP issued a draft NPDES Permit Renewal that, if finalized as proposed, would moot the appeal and reduce the estimated capital investment requirements. 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. On July 17, 2018, the EPA Administrator signed a final rule extending the deadline for certain CCR facilities to cease disposal and commence closure activities, as well as, establishing less stringent groundwater monitoring and protection requirements. On August 21, 2018, the D.C. Circuit remanded sections of the CCR Rule to the EPA to provide additional safeguards for unlined CCR impoundments that are more protective of human health and the environment. AE Supply assessed the changes in timing and closure plan requirements associated with the McElroy's Run impoundment site and increased the ARO by approximately $43 million in the third quarter of 2018.

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, West Virginia, and the remainder recycled into drywall by National Gypsum. These beneficial reuse options are expected to 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. As noted above, FE provides credit support for FG surety bonds of $169 million and $31 million for the benefit of the PA DEP with respect to LBR and the Hatfield's Ferry disposal site, respectively.

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, 2018, based on estimates of the total costs of cleanup, FirstEnergy's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $121 million have been accrued through December 31, 2018, including approximately $85 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. FE 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, JCP&L, ME and PN must ensure that adequate funds will be available to decommission their retired nuclear facility, TMI-2. As of December 31, 2018, JCP&L, ME and PN had in total approximately $790 million invested in external trusts to be used for the decommissioning and environmental remediation of their retired TMI-2 nuclear generating facility. The values of these NDTs also fluctuate based on market conditions. If the values of the trusts decline by a material amount, the obligation to JCP&L, ME and PN 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.

FES Bankruptcy

On March 31, 2018, FES, including its consolidated subsidiaries, FG, NG, FE Aircraft Leasing Corp., Norton Energy Storage L.L.C. and FGMUC, and FENOC filed voluntary petitions for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court. See Note 3, "Discontinued Operations," for additional information.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FE or its subsidiaries. The loss or range of loss in these matters is not expected to be material to FE or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 16, "Regulatory Matters," of the 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 FE 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 FE'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 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. In connection with adopting the new revenue recognition guidance in 2018, FirstEnergy has elected the optional invoice practical expedient for most of its revenues and, with the exception of JCP&L transmission revenues, utilizes the optional short-term contract exemption for transmission revenues due to the annual establishment of revenue requirements, which eliminates the need to provide certain revenue disclosures regarding unsatisfied performance obligations. See Note 2, "Revenue," for additional information.

Regulatory Accounting

FirstEnergy’s Regulated Distribution and Regulated Transmission segments are subject to regulations that set the prices (rates) the Utilities, AGC, and the Transmission Companies 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. Certain regulatory assets are recorded based on prior precedent or anticipated recovery based on rate making premises without a specific rate order. 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 16, "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. FirstEnergy considers the entire regulatory asset balance as the unit of account for the purposes of balance sheet classification rather than the next years recovery and as such net regulatory assets and liabilities are presented in the non-current section on the FirstEnergy Consolidated Balance Sheets.

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, 2018, 2017, and 2016, were $145 million, $141 million, and $147 million, respectively, of these amounts, approximately $1 million, $39 million, and $45 million are included in discontinued operations.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pension were 4.44%, 3.75% and 4.25% as of December 31, 2018, 2017 and 2016, respectively. The assumed discount rates for OPEB were 4.30%, 3.50% and 4.00% as of December 31, 2018, 2017 and 2016, respectively.

Effective in 2019, FirstEnergy changed the approach utilized to estimate the service cost and interest cost components of net periodic benefit cost for pension and OPEB plans. Historically, FirstEnergy estimated these components utilizing a single, weighted average discount rate derived from the yield curve used to measure the benefit obligation. FirstEnergy has elected to use a spot rate approach in the estimation of the components of benefit cost by applying specific spot rates along the full yield curve to the relevant projected cash flows, as this provides a better estimate of service and interest costs by improving the correlation between projected benefit cash flows to the corresponding spot yield curve rates. This change did not affect the measurement of total benefit obligations or annual net period benefit cost and the change in service and interest cost is offset in the actuarial mark-to-market adjustment reported. This election is considered a change in estimate and, accordingly, accounted prospectively.

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 2018, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $371 million or (4.0)%, compared to gains of $999 million, or 15.1% in 2017, and losses of $472 million, or 8.2% in 2016 and assumed a 7.50% rate of return on plan assets in 2018, 2017 and 2016, which generated $605 million, $478 million and $429 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 2019 is 7.50%.

During 2018, the Society of Actuaries released its updated mortality improvement scale for pension plans, MP-2018, incorporating SSA mortality data from 2014-2016. The updated improvement scale indicates a slight decline in life expectancy. Due to the additional data on population mortality, the RP2014 mortality table with the projection scale MP-2018 was utilized to determine the 2018 benefit cost and obligation as of December 31, 2018, for the FirstEnergy pension and OPEB plans. The impact of using the projection scale MP-2018 resulted in a decrease in the projected pension benefit obligation of approximately $16 million and was included in the 2018 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.44% for pension, 4.30% for OPEB and an estimated return on assets of 7.50%, FirstEnergy expects its 2019 pre-tax net periodic benefit credit to be approximately $28 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2019). 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, 2018, 2017, and 2016:

Postemployment Benefits Expense (Credits)	2018	2017	2016
	(In millions)		
Pension	$200	$247	$277
OPEB	(158)	(45)	(40)
Total	$42	$202	$237

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 2018 and 2017, 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 2019 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 0.25%	$288	$ 15	$303
Long-term return on assets	Decrease by 0.25%	$18	$ 1	$19
Health care trend rate	Increase by 1.0%	N/A	$ 22	$22

See Note 5, "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 1, "Organization and Basis of Presentation - Asset impairments," for impairments recognized in 2018, 2017 and 2016.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plant 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 FirstEnergy'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. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation AROs, considering the expected timing of settlement of the ARO based on the expected economic useful life of associated asset and/or regulatory requirements. 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. In certain circumstances, FirstEnergy has recovery of asset retirement costs and, as such, certain accretion and depreciation is offset against regulatory assets.

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, 2018, are described further in Note 15, "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 in its financial statements 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 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 7, "Taxes," for additional information.

On December 22, 2017, the President signed into law the Tax Act, which included significant changes to the Internal Revenue Code of 1986 (as amended, the Code). The more significant changes that impacted FirstEnergy were as follows:

- 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.

At December 31, 2017, FirstEnergy 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), recorded provisional income tax amounts 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 Tax Act, qualified property acquired and placed into service after September 27, 2017 would be eligible for full expensing for all taxpayers other than regulated utilities. On August 3, 2018, the IRS released proposed regulations clarifying the immediate expensing of qualified property, specifically addressing that regulated utility property acquired after September 27, 2017, and placed into service by December 31, 2017, qualifies for full expensing. While not final as of December 31, 2018, corporate taxpayers may rely on the proposed regulations for tax years ending after September 27, 2017. As of December 31, 2018, FirstEnergy has now completed its accounting for all of the enactment-date income tax effects of the Tax Act, resulting in an immaterial adjustment to the provisional income tax amounts recorded at December 31, 2017.

The Tax Act also amended Section 163(j) of the Code, limiting interest expense deductions for corporations, with exemption for certain regulated utilities. On November 26, 2018, the IRS issued proposed regulations implementing Section 163(j), including its application of the rules to consolidated groups with both regulated utility and non-regulated members. Based on its interpretation of these proposed regulations, FirstEnergy has estimated the amount of deductible interest for its consolidated group in 2018 and has recorded a deferred tax asset on the nondeductible portion as it is carried forward with an indefinite life. The deferred tax asset related to the indefinite lived carryforward of nondeductible interest has a full valuation allowance ($60 million) recorded against it as future profitability from sources other than regulated utility businesses is required for utilization. Of this tax effected nondeductible interest, $27 million has been reflected as an uncertain tax position. All tax expense related to nondeductible interest in 2018 has been recorded in discontinued operations as it is entirely attributed to the anticipated inclusion of entities reported in discontinued operations in FirstEnergy's consolidated federal tax return.

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 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, 2018, 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 values and a quantitative analysis was not necessary.

See Note 3, "Discontinued Operations", for further discussion of CES' goodwill impairment charges recognized in 2016.

NEW ACCOUNTING PRONOUNCEMENTS

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 evaluated its revenues and determined the new guidance had immaterial impacts to 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 did not record a cumulative effect 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 were implemented. See Note 2, "Revenue," for additional information on FirstEnergy's revenues.

ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities" (Issued January 2016 and subsequently updated in 2018): 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. FirstEnergy adopted this standard on January 1, 2018, and recognizes 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 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 this standard, FirstEnergy recorded a cumulative effect adjustment to retained earnings of $57 million on January 1, 2018, representing unrealized gains on equity securities with FES NDTs that were previously recorded to AOCI. Following deconsolidation of the FES Debtors, the adoption of this standard is not expected to have a material impact on FirstEnergy's financial statements as the majority of its gains and losses on equity securities are offset against a regulatory asset or liability.

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. As a result of adopting this standard, FirstEnergy's statement of cash flows reports changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents. Prior periods have been recast to conform to the current year presentation.

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. FirstEnergy adopted ASU 2017-01 on January 1, 2018. The ASU will be applied prospectively to future transactions.

ASU 2017-04, "Goodwill Impairment" (Issued January 2017): ASU 2017-04 simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. FirstEnergy has elected to early adopt ASU 2017-04 as of January 1, 2018, and will apply this standard on a prospective basis.

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. In addition, only service costs are eligible for capitalization on a prospective basis. FirstEnergy adopted ASU 2017-07 on January 1, 2018. Because the non-service cost components of net benefit cost are no longer eligible for capitalization after December 31, 2017, FirstEnergy has recognized these components in income as a result of adopting this standard. FirstEnergy reclassified approximately $27 million and $6 million of non-service costs from Other operating expenses to Miscellaneous income, net, for the years ended December 31, 2017 and December 31, 2016, respectively.

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. FirstEnergy early adopted this standard during the first quarter of 2018 and has elected to present the change in the period of adoption. Upon adoption, FirstEnergy recorded a $22 million cumulative effect adjustment for stranded tax effects, such as pension and OPEB prior service costs and losses on derivative hedges, to retained earnings on January 1, 2018, of which $8 million was related to the FES Debtors.

ASU 2018-05, "Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118" (Issued March 2018): ASU 2018-05, effective 2018, expands income tax accounting and disclosure guidance to include SAB 118 issued by the SEC in December 2017. SAB 118 provides guidance on accounting for the income tax effects of the Tax Act and among other things allows for a measurement period not to exceed one year for companies to finalize the provisional amounts recorded as of December 31, 2017. See Note 7, "Taxes," for additional information on FirstEnergy's accounting for the Tax Act.

ASU 2018-13, "Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement" (Issued August 2018): ASU 2018-13 eliminates, adds and modifies certain disclosure requirements for fair value measurements as part of the FASB's disclosure framework project. Entities will no longer be required to disclose the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, but public companies will be required to disclose the range and weighted average used to develop significant unobservable inputs for Level 3 fair value measurements. Entities are permitted to early adopt either the entire standard or only the provisions that eliminate or modify the requirements. FirstEnergy early adopted all the provisions of this standard as of December 31, 2018 which are reflected in Note 11, "Fair Value Measurements".

ASU 2018-14, "Compensation-Retirement Benefits-Defined Benefit Plans-General (Subtopic 715-20): Disclosure Framework-Changes to the Disclosure Requirements for Defined Benefit Plans" (Issued August 2018): ASU 2018-14 amends ASC 715 to add, remove, and clarify disclosure requirements related to defined benefit pension and other postretirement plans. FirstEnergy early adopted ASU 2018-14 as of December 31, 2018 and the provisions of this standard are reflected within Note 5, "Pension and Other Postemployment Benefits".

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB was not adopted in 2018. 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 2016-02, "Leases (Topic 842)" (Issued February 2016 and subsequently updated to address implementation questions): The new guidance 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 as well as new qualitative and quantitative disclosures. FirstEnergy has implemented a third-party software tool that will assist with the initial adoption and ongoing compliance. The standard provides a number of transition practical expedients that entities may elect. These include a "package of three" expedients that must be taken together and allow entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. A separate practical expedient allows entities to not evaluate land easements under the new guidance at adoption if they were not previously accounted for as leases. Additionally, entities have the option to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. FirstEnergy elected all of these practical expedients. Upon adoption, on January 1, 2019, FirstEnergy increased assets and liabilities by approximately $190 million, with no impact to results of operations or cash flows.

ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments” (issued June 2016 and subsequently updated): 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 2018-15, "Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" (Issued August 2018): ASU 2018-15 requires implementation costs incurred by customers in cloud computing arrangements to be deferred and recognized over the term of the arrangement, if those costs would be capitalized by the customers in a software licensing arrangement. The guidance will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted.

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

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 (the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of income (loss), of comprehensive income (loss), of stockholders’ equity, and of cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 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, 2018, 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.

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 19, 2019

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(In millions, except per share amounts)	For the Years Ended December 31, 2018	2017	2016
REVENUES:			
Distribution services and retail generation	$8,937	$8,685	$8,685
Transmission	1,335	1,307	1,123
Other	989	936	892
Total revenues[1]	11,261	10,928	10,700
OPERATING EXPENSES:			
Fuel	538	497	571
Purchased power	3,109	2,926	3,310
Other operating expenses	3,133	2,761	2,579
Provision for depreciation	1,136	1,027	933
Amortization (deferral) of regulatory assets, net	(150)	308	297
General taxes	993	940	913
Impairment of assets (Note 1)	—	41	43
Total operating expenses	8,759	8,500	8,646
OPERATING INCOME	2,502	2,428	2,054
OTHER INCOME (EXPENSE):			
Miscellaneous income, net	205	53	44
Pension and OPEB mark-to-market adjustment	(144)	(102)	(102)
Interest expense	(1,116)	(1,005)	(973)
Capitalized financing costs	65	52	55
Total other expense	(990)	(1,002)	(976)
INCOME BEFORE INCOME TAXES	1,512	1,426	1,078
INCOME TAXES	490	1,715	527
INCOME (LOSS) FROM CONTINUING OPERATIONS	1,022	(289)	551
Discontinued operations (Note 3)[2]	326	(1,435)	(6,728)
NET INCOME (LOSS)	$1,348	$(1,724)	$(6,177)
INCOME ALLOCATED TO PREFERRED STOCKHOLDERS (Note 1)	367	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$981	$(1,724)	$(6,177)
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$1.33	$(0.65)	$1.29
Basic - Discontinued Operations	0.66	(3.23)	(15.78)

Basic - Net Income (Loss) Attributable to Common Stockholders	$1.99	$(3.88)	$(14.49)
Diluted - Continuing Operations	$1.33	$(0.65)	$1.29
Diluted - Discontinued Operations	0.66	(3.23)	(15.78)
Diluted - Net Income (Loss) Attributable to Common Stockholders	$1.99	$(3.88)	$(14.49)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	492	444	426
Diluted	494	444	426

(1) Includes excise and gross receipts tax collections of $386 million