Section 1: 10-K (10-K)

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

FORM 10-K
(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the FISCAL YEAR ended December 31, 2019

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:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, $0.10 par value per share	FE	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 ☑ No ☐

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 ☐ No ☑

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 ☑ No ☐

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 ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an 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	☑
Accelerated Filer	☐
Non-accelerated Filer	☐
Smaller Reporting Company	☐
Emerging Growth Company	☐

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. ☐

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

Yes ☐ No ☑

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.

$22,724,895,037 as of June 30, 2019

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, 2020
Common Stock, $0.10 par value	540,713,909

Documents Incorporated By Reference

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2020 Annual Meeting of Shareholders of FirstEnergy Corp. to be held May 19, 2020	Part III

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GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, a subsidiary of FirstEnergy Corp.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, 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
GPUN	GPU Nuclear, Inc., a subsidiary of FE, which operates TMI-2
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:

ACE	Affordable Clean Energy	EDC	Electric Distribution Company
ADIT	Accumulated Deferred Income Taxes	EDCP	Executive Deferred Compensation Plan
AEP	American Electric Power Company, Inc.	EDIS	Electric Distribution Investment Surcharge
AFS	Available-for-sale	EE&C	Energy Efficiency and Conservation
AFUDC	Allowance for Funds Used During Construction	EGS	Electric Generation Supplier
ALJ	Administrative Law Judge	EGU	Electric Generation Units
AMT	Alternative Minimum Tax	EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ANI	American Nuclear Insurers	ENEC	Expanded Net Energy Cost
AOCI	Accumulated Other Comprehensive Income	EPA	United States Environmental Protection Agency
ARO	Asset Retirement Obligation	EPS	Earnings per Share
ARP	Alternative Revenue Program	ERO	Electric Reliability Organization
ASC	Accounting Standard Codification	ESOP	Employee Stock Ownership Plan
ASU	Accounting Standards Update	ESP IV	Electric Security Plan IV
AYE DCD	Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors	Facebook®	Facebook is a registered trademark of Facebook, Inc.
AYE Director's Plan	Allegheny Energy, Inc. Non-Employee Director Stock Plan	FASB	Financial Accounting Standards Board
Bankruptcy Court	U.S. Bankruptcy Court in the Northern District of Ohio in Akron	FE Tomorrow	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
Bath County	Bath County Pumped Storage Hydro-Power Station	FERC	Federal Energy Regulatory Commission
BGS	Basic Generation Service	FES Bankruptcy	FES Debtors' voluntary petitions for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code with the Bankruptcy Court
BNSF	BNSF Railway Company	Fitch	Fitch Ratings
bps	Basis points	FMB	First Mortgage Bond
CAA	Clean Air Act	FPA	Federal Power Act
CBA	Collective Bargaining Agreement	FTR	Financial Transmission Right
CCR	Coal Combustion Residuals	GAAP	Accounting Principles Generally Accepted in the United States of America
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980	GHG	Greenhouse Gases
CFL	Compact Fluorescent Light	IBEW	International Brotherhood of Electrical Workers
CFR	Code of Federal Regulations	ICP 2007	FirstEnergy Corp. 2007 Incentive Compensation Plan
CO2	Carbon Dioxide	ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan
CPP	EPA's Clean Power Plan	IIP	Infrastructure Investment Program
CSAPR	Cross-State Air Pollution Rule	IRS	Internal Revenue Service
CSX	CSX Transportation, Inc.	ISO	Independent System Operator
CTA	Consolidated Tax Adjustment	JCP&L Reliability Plus	JCP&L Reliability Plus IIP
CWA	Clean Water Act	kV	Kilovolt
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit	KWH	Kilowatt-hour
DCPD	Deferred Compensation Plan for Outside Directors	LBR	Little Blue Run
DCR	Delivery Capital Recovery	LED	Light Emitting Diode
DMR	Distribution Modernization Rider	LIBOR	London Interbank Offered Rate
DPM	Distribution Platform Modernization	LOC	Letter of Credit
DSIC	Distribution System Improvement Charge	LS Power	LS Power Equity Partners III, LP
DSP	Default Service Plan	LSE	Load Serving Entity
DTA	Deferred Tax Asset	LTIIPs	Long-Term Infrastructure Improvement Plans

E&P	Earnings and Profits	MDPSC	Maryland Public Service Commission

MGP	Manufactured Gas Plants
MISO	Midcontinent Independent System Operator, Inc.
mmBTU	One Million British Thermal Units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOL	Net Operating Loss
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
OMAEG	Ohio Manufacturers' Association Energy Group
OPEB	Other Post-Employment Benefits
OPEIU	Office and Professional Employees International Union
OPIC	Other Paid-in Capital
OSHA	Occupational Safety and Health Administration
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Purchase Power Agreement
PPB	Parts per Billion
PPUC	Pennsylvania Public Utility Commission
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
Regulation FD	Regulation Fair Disclosure promulgated by the SEC
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RSS	Rich Site Summary
RSU	Restricted Stock Unit
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SCOH	Supreme Court of Ohio
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan(s) Under the Clean Air Act
SO2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
SVC	Static Var Compensator
Tax Act	Tax Cuts and Jobs Act adopted December 22, 2017
TMI-2	Three Mile Island Unit 2
Twitter®	Twitter is a registered trademark of Twitter, Inc.
UCC	Official committee of unsecured creditors appointed in connection with the FES Bankruptcy
UWUA	Utility Workers Union of America
VEPCO	Virginia Electric and Power Company
VIE	Variable Interest Entity
VMS	Vegetation Management Surcharge
VSCC	Virginia State Corporation Commission
WVPSC	Public Service Commission of West Virginia

PART I

ITEM 1. BUSINESS

The Companies

FE was incorporated under Ohio law in 1996. FE’s principal business is the holding, directly or indirectly, of all of the outstanding equity of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, AE Supply, MP, AGC, 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: AESC, FirstEnergy Properties, Inc., FEV, FELHC, Inc., GPUN, Allegheny Ventures, Inc., and Suvon, LLC doing business as both FirstEnergy Home and FirstEnergy Advisors.

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 the Utilities and Transmission Companies.

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. Also, PN, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, serves approximately 4,000 customers in the Waverly, New York vicinity. The area PN serves has a population of approximately 1.2 million.

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 16.25% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility (487 MWs) 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 7,890 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 4,260 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, the FES Debtors 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 the FES Debtors as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, the FES Debtors were deconsolidated from FirstEnergy’s consolidated financial statements. Since such time, FE has accounted and will account for its investments in the FES Debtors at fair values of zero. FE concluded that in connection with the disposal, the FES Debtors 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. As part of the FES Bankruptcy settlement agreement, discussed below, AE Supply transferred the Pleasants Power Station and related assets to a newly formed subsidiary of FG on January 30, 2020. AE Supply will continue to provide Pleasants Power Station disposal access to the McElroy's Run Impoundment Facility pursuant to a separate agreement among the parties.

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, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the 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, 2019, 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. Effective January 1, 2020, JPC&L's transmission rates became forward-looking formula rates, subject to refund, pending further hearing and settlement proceedings. 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.

Corporate/Other 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, 2019, 67 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of Corporate/Other. As of December 31, 2019, Corporate/Other had approximately $7.1 billion of FE holding company debt.

Utility Regulation

Regulatory Accounting

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities 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 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 from/return 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 from/returned to customers. Based on current ratemaking procedures, the Utilities and the Transmission Companies continue to collect cost-based rates for their transmission and distribution services; accordingly, it is appropriate that the Utilities 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 New Jersey by the NJBPU, in Ohio by the PUCO, 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 base distribution rate orders in effect for the Utilities as of December 31, 2019:

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)	March 2019	47% / 53%	9.65%
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 wholesale services and rates, the Utilities, AE Supply, and the Transmission Companies are subject to regulation by FERC. Under the FPA, FERC regulates rates and terms and conditions of service 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 as of December 31, 2019:

Company	Rates Effective	Capital Structure	Allowed ROE
ATSI	January 1, 2015	Actual (13 month average)	10.38%
JCP&L	June 1, 2017[(1)]	Settled[(1)(3)]	Settled[(1)(3)]
MP	March 21, 2018[(2)]	Settled[(3)]	Settled[(3)]
PE	March 21, 2018[(2)]	Settled[(3)]	Settled[(3)]
WP	March 21, 2018[(2)]	Settled[(3)]	Settled[(3)]
MAIT	July 1, 2017	Lower of Actual (13 month average) or 60%	10.3%
TrAIL	July 1, 2008	Actual (year-end)	12.7% (TrAIL the Line & Black Oak SVC) 11.7% (All other projects)

(1) Effective on January 1, 2020, JCP&L has implemented a forward-looking formula rate, which has been accepted by FERC, subject to refund, pending further hearing and settlement proceedings.
(2) See FERC Actions on Tax Act below.
(3) FERC-approved settlement agreements did not specify.

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 six 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 material 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.

Maryland Regulatory Matters

PE operates under MDPSC approved base rates that were effective as of March 23, 2019. 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 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.

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. The MDPSC approved PE's compliance filing, which implements the pilot program, with minor modifications, on July 3, 2019.

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 reflected $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On March 22, 2019, the MDPSC issued a final order that approved a rate increase of $6.2 million, approved three of the four EDIS programs for four years, directed PE to file a new depreciation study within 18 months, and ordered the filing of a new base rate case in four years to correspond to the ending of the approved EDIS programs.

New Jersey Regulatory Matters

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

On April 18, 2019, pursuant to the May 2018 New Jersey enacted legislation establishing a ZEC program to provide ratepayer funded subsidies of New Jersey nuclear energy supply, the NJBPU approved the implementation of a non-bypassable, irrevocable ZEC charge for all New Jersey electric utility customers, including JCP&L's customers. Once collected from customers by JCP&L, these funds will be remitted to eligible nuclear energy generators.

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 ratepayers; 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. On May 17, 2019, the Rate Counsel filed an appeal with the Appellate Division of the Superior Court of New Jersey. JCP&L is contesting this appeal but is unable to predict the outcome of this matter.

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 April 23, 2019, JCP&L filed a Stipulation of Settlement with the NJBPU on behalf of the JCP&L, Rate Counsel, NJBPU Staff and New Jersey Large Energy Users Coalition, which provides that JCP&L will invest up to approximately $97 million in capital investments beginning on June 1, 2019 through December 31, 2020. JCP&L shall seek recovery of the capital investment through an accelerated cost recovery mechanism, provided for in the rules, that includes a revenue adjustment calculation and a process for two rate adjustments. On May 8, 2019, the NJBPU issued an order approving the Stipulation of Settlement without modifications. Pursuant to the Stipulation, JCP&L filed a petition on September 16, 2019, to seek approval of rate adjustments to provide for cost recovery established with JCP&L Reliability Plus.

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. On April 23, 2019, JCP&L filed a Stipulation of Settlement on behalf of the Rate Counsel, NJBPU Staff, and the New Jersey Large Energy Users Coalition with the NJBPU. The terms of the Stipulation of Settlement provide that between January 1, 2018 and March 31, 2018, JCP&L's refund obligation is estimated to be approximately $7 million, which was refunded to customers in 2019. The Stipulation of Settlement also provides for a base rate reduction of $28.6 million, which was reflected in rates on April 1, 2018, and a Rider Tax Act Adjustment for certain items over a five-year period. On May 8, 2019, the NJBPU issued an order approving the Stipulation of Settlement without modification.

JCP&L expects to file a distribution base rate case in New Jersey in February 2020, which will seek to recover certain costs associated with providing safe and reliable electric service to JCP&L customers, along with recovery of previously incurred storm costs.

Ohio Regulatory Matters

The Ohio Companies operate under base distribution rates approved by the PUCO effective in 2009. The Ohio Companies' residential and commercial base distribution revenues are decoupled, through a mechanism that took effect on February 1, 2020, to the base distribution revenue and lost distribution revenue associated with energy efficiency and peak demand reduction programs recovered as of the twelve-month period ending on December 31, 2018. The Ohio Companies currently operate under ESP IV effective June 1, 2016, and continuing through May 31, 2024, that continues the supply of power to non-shopping customers at a market-based price set through an auction process. ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $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. In addition, ESP IV includes: (1) continuation of a base distribution rate freeze through May 31, 2024; (2) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; and (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.

ESP IV further provided for the Ohio Companies to collect through Rider DMR $132.5 million annually for three years beginning in 2017, grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. Revenues from Rider DMR are excluded from the significantly excessive earnings test. On appeal, the SCOH, on June 19, 2019, reversed the PUCO's determination that Rider DMR is lawful, and remanded the matter to the PUCO with instructions to remove Rider DMR from ESP IV. On August 20, 2019, the SCOH denied the Ohio Companies' motion for reconsideration. The PUCO entered an Order directing the Ohio Companies to cease further collection through Rider DMR, credit back to customers a refund of Rider DMR funds collected since July 2, 2019, and remove Rider DMR from ESP IV. On October 1, 2019, the Ohio Companies implemented PUCO approved tariffs to refund approximately $28 million to customers, including Rider DMR revenues billed from July 2, 2019 through August 31, 2019.

On July 15, 2019, OCC filed a Notice of Appeal with the SCOH, challenging the PUCO's exclusion of Rider DMR revenues from the determination of the existence of significantly excessive earnings under ESP IV for calendar year 2017 and claiming a $42 million refund is due to OE customers. The Ohio Companies are contesting this appeal but are unable to predict the outcome of this matter.

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 includes a portfolio of energy efficiency programs targeted to a variety of customer segments. The Ohio Companies anticipate the cost of the plan will be approximately $268 million over the life of the plan 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 plan 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 October 15, 2019, the SCOH reversed the PUCO's decision to impose the 4% cost-recovery cap and remanded the matter to the PUCO for approval of the portfolio plans without the cost-recovery cap.

On July 23, 2019, Ohio enacted legislation establishing support for nuclear energy supply in Ohio. In addition to the provisions supporting nuclear energy, the legislation included a provision implementing a decoupling mechanism for Ohio electric utilities. The legislation also is ending current energy efficiency program mandates on December 31, 2020, provided statewide energy efficiency mandates are achieved as determined by the PUCO. On October 23, 2019, the PUCO solicited comments on whether the PUCO should terminate the energy efficiency programs once the statewide energy efficiency mandates are achieved. Opponents to the legislation sought to submit it to a statewide referendum, and stay its effect unless and until approved by a majority of Ohio voters. Petitioners filed a lawsuit in the U.S. District Court for the Southern District of Ohio seeking additional time to gather signatures in support of a referendum. Petitioners failed to file the necessary number of petition signatures, and the legislation took effect on October 22, 2019. On October 23, 2019, the U.S. District Court denied petitioners' request for more time, and certified questions of state law to the SCOH to answer. Petitioners appealed the U.S. District Court's decision to the U.S. Court of Appeals for the Sixth Circuit. The Petitioners ended their challenge to the legislation voluntarily at the end of January 2020 causing the dismissal of the appeal, the lawsuit before the U.S District Court, and the proceedings before the SCOH.

On November 21, 2019, the Ohio Companies applied to the PUCO for approval of a decoupling mechanism, which would set residential and commercial base distribution related revenues at the levels collected in 2018. As such, those base distribution revenues would no longer be based on electric consumption, which allows continued support of energy efficiency initiatives while also providing revenue certainty to the Ohio Companies. On January 15, 2020, the PUCO approved the Ohio Companies' decoupling application, and the decoupling mechanism took effect on February 1, 2020.

In February 2016, the Ohio Companies filed a Grid Modernization Business Plan for PUCO consideration and approval, as required by the terms of ESP IV. On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan, a portfolio 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. Also, on January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act on Ohio utilities' rates and determine the appropriate course of action to pass benefits on to customers. 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 to flow back to customers. 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 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 had 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. On July 17, 2019, the PUCO approved the settlement agreement with no material modifications. On September 11, 2019, the PUCO denied the application for rehearing of environmental advocates who were not parties to the settlement.

The Ohio Companies' Rider NMB is designed to recover NMB transmission-related costs imposed on or charged to the Ohio Companies by FERC or PJM. On December 14, 2018, the Ohio Companies filed an application for a review of their 2019 Rider NMB, including recovery of future Legacy RTEP costs and previously absorbed Legacy RTEP costs, net of refunds received from PJM. On February 27, 2018, the PUCO issued an order directing the Ohio Companies to file revised final tariffs recovering Legacy RTEP costs incurred since May 31, 2018, but excluding recovery of approximately $95 million in Legacy RTEP costs incurred prior to May 31, 2018, net of refunds received from PJM. The PUCO solicited comments on whether the Ohio Companies should be permitted to recover the Legacy RTEP charges incurred prior to May 31, 2018. On October 9, 2019, the PUCO approved the recovery of the $95 million of previously excluded Legacy RTEP charges.

Pennsylvania Regulatory Matters

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. These rates were adjusted for the net impact of the Tax Act, effective March 15, 2018. The net impact of the Tax Act for the period January 1, 2018 through March 14, 2018 must also be separately tracked for treatment in a future rate proceeding. The Pennsylvania Companies operate under DSPs for the June 1, 2019 through May 31, 2023 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 2019-2023 DSPs, 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, modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW, customer assistance program shopping limitations, and script modifications related to the Pennsylvania Companies' customer referral programs.

Pursuant to Pennsylvania 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. 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. Following a periodic review of the LTIIPs in 2018 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 May 23, 2019, the PPUC approved the Pennsylvania Companies' Modified LTIIPs that revised LTIIP spending in 2019 of approximately $45 million by ME, $25 million by PN, $26 million by Penn and $51 million by WP, and terminating at the end of 2019. On August 30, 2019, the Pennsylvania Companies filed Petitions for approval of proposed LTIIPs for the five-year period beginning January 1, 2020 and ending December 31, 2024 for a total capital investment of approximately $572 million for certain infrastructure improvement initiatives. On January 16, 2020, the PPUC approved the LTIIPs without modification, as well as directed the Pennsylvania Companies to submit corrective action plans by March 16, 2020, which outline how they will reduce their pole replacement backlogs over a five-year period to a rolling two-year backlog.

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. The parties to the DSIC proceeding submitted a Joint Settlement that resolved the issues that were pending from the order issued on June 9, 2016, and 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. The Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision, and the Pennsylvania Companies contested the appeal. The Commonwealth Court reversed the PPUC's decision of April 19, 2018 and remanded the matter to the PPUC to require the Pennsylvania Companies to revise their tariffs and DSIC calculations to include ADIT and state income taxes. The Commonwealth Court denied Applications for Reargument in the Court's July 11, 2019 Opinion and Order filed by the PPUC and the Pennsylvania Companies. On October 7, 2019, the PPUC and the Pennsylvania Companies filed separate Petitions for Allowance of Appeal of the Commonwealth Court's Opinion and Order to the Pennsylvania Supreme Court.

On August 30, 2019, Penn filed a Petition seeking approval of a waiver of the statutory DSIC cap of 5% of distribution rate revenue and approval to increase the maximum allowable DSIC to 11.81% of distribution rate revenue for the five-year period of its proposed LTIIP. The Pennsylvania Office of Small Business Advocate, the PPUC's Bureau of Investigation, and the Pennsylvania OCA opposed Penn's Petition. On January 17, 2020, the parties filed a petition seeking approval of settlement that provides for a temporary increase in the recoverability cap from 5% to 7.5%, which will expire on the earlier of the effective date of new base rates following Penn's next base rate case or the expiration of its LTIIP II program. The settlement is subject to PPUC approval.

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.

On August 21, 2019, MP and PE filed with the WVPSC their annual ENEC case requesting a decrease in ENEC rates of $6.1 million beginning January 1, 2020, representing a 0.4% decrease in rates versus those in effect on August 21, 2019. On October 11, 2019, MP and PE filed a supplement requesting approval of the termination of the 50 MW PPA with Morgantown Energy Associates, a NUG entity. A settlement between MP, PE, and the majority of the intervenors fully resolving the ENEC case, which maintains 2019 ENEC rates into 2020, and supports the termination of the Morgantown Energy Associates PPA, was filed with the WVPSC on October 18, 2019. An order was issued on December 20, 2019, approving the ENEC settlement and termination of the PPA with Morgantown Energy Associates.

On August 21, 2019, MP and PE filed with the WVPSC for a reconciliation of their VMS and a periodic review of its vegetation management program requesting an increase in VMS rates of $7.6 million beginning January 1, 2020. The increase is due to moving from a 5-year maintenance cycle to a 4-year cycle and performing more operation and maintenance work and less capital work on the rights of way. The increase is a 0.5% increase in rates versus those in effect on August 21, 2019. All the parties reached a settlement in the case, and the WVPSC issued its order approving the settlement without change on December 20, 2019.

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 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 six 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 material 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.

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.

FERC Actions on Tax Act

On March 15, 2018, FERC initiated proceedings on the question of how to 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 21, 2019, FERC issued a final rule (Order 864). Order 864 requires utilities with transmission formula rates to update their formula rate templates to include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate base; (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. Alternatively, formula rate utilities can demonstrate to FERC that their formula rate template already achieves these outcomes. Utilities with transmission stated rates are required to address these new requirements as part of their next transmission rate case. 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. FirstEnergy’s formula rate transmission utilities will make the required filings on or before the deadlines established in FERC’s order. FirstEnergy’s stated rate transmission utilities will address the requirements as part of their next transmission rate case. JCP&L is addressing the requirements in the course of its pending transmission rate case.

Transmission ROE Methodology

FERC’s methodology for calculating electric transmission utility ROE has been in transition as a result of an April 14, 2017 ruling by the D.C. Circuit that vacated FERC’s then-effective methodology. On October 16, 2018, FERC issued an order in which it proposed a revised ROE methodology. FERC proposed that, for complaint proceedings alleging that an existing ROE is not just and reasonable, FERC will rely on three financial models - discounted cash flow, capital-asset pricing, and expected earnings - to establish a composite zone of reasonableness to identify 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 replacement 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. On March 21, 2019, FERC established NOIs to collect industry and stakeholder comments on the revised ROE methodology that is described in the October 16, 2018 decision, and also whether to make changes to FERC’s existing policies and practices for awarding transmission rates incentives. On November 21, 2019, FERC announced in a complaint proceeding involving MISO utilities that FERC would rely on the discounted cash flow and capital-asset pricing models as the basis for establishing ROE. It is not clear at this time whether FERC’s November ruling will be applied more broadly. Any changes to FERC’s transmission rate ROE and incentive policies would be applied on a prospective basis. FirstEnergy currently is participating through various trade groups in the FERC dockets where the ROE methodology is being reviewed, and on December 23, 2019, JCP&L filed a request for rehearing of FERC’s November decision in the MISO utilities docket.

JCP&L Transmission Formula Rate

On October 30, 2019, JCP&L filed tariff amendments with FERC to convert JCP&L’s existing stated transmission rate to a forward-looking formula transmission rate. JCP&L requested that the tariff amendments become effective January 1, 2020. On December 19, 2019, FERC issued its initial order in the case, allowing JCP&L to transition to a forward-looking formula rate as of January 1, 2020 as requested, subject to refund, pending further hearing and settlement proceedings. JCP&L is engaged in settlement negotiations.

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.

As previously disclosed, 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 equity investment strengthened the Company's balance sheet, supported the company's transition to a fully regulated utility company and positions FirstEnergy for sustained investment-grade credit metrics. The shares of preferred stock participated in the dividend paid on common stock on an as-converted basis and were non-voting except in certain limited circumstances. Because of this investment, FirstEnergy does not currently anticipate the need to issue additional equity through 2021 and expects to issue, subject to, among other things, market conditions, pricing terms and business operations, up to $600 million of equity annually in 2022 and 2023, including approximately $100 million in equity for its regular stock investment and employee benefit plans. As of August 1, 2019, an aggregate of 1,616,000 shares of preferred stock had been converted into 58,935,078 shares of common stock, and as a result, there were no shares of preferred stock outstanding as of December 31, 2019.

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 2020 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 by FE and certain of its 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.

On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. FirstEnergy expects no required contributions through 2021.

As part of the Energizing the Future initiative, the Center for Advanced Technology was opened in Akron, Ohio in April 2019. The 88,000 square feet facility was designed to be a hands-on environment where engineers and technicians can develop and evaluate new technology and grid solutions and simulate a variety of real-world conditions.

Capital expenditures for 2018 and 2019 and forecasted expenditures for 2020, 2021, 2022, and 2023, by reportable segment are included below:

Reportable Segment	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
				(In millions)		
Regulated Distribution	$ 1,635	$ 1,698	$ 1,700	$ 1,700	$ 1,700	$ 1,700
Regulated Transmission	1,165	1,189	1,200	1,200 - 1,450	1,200 - 1,450	1,200 - 1,450
Corporate/Other	183	105	90	110	110	110
Total	$ 2,983	$ 2,992	$ 2,990	$ 3,010 - 3,260	$ 3,010 - 3,260	$ 3,010 - 3,260

FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of over $20 billion beyond those identified through 2023, 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.

With an operating territory of 65,000 square miles, the scale and diversity of the ten Utilities that comprise the Regulated Distribution business uniquely position this business for growth through opportunities for additional investment. Over the past several years, Regulated Distribution has experienced rate base growth through investments that have improved reliability and added operating flexibility to the distribution infrastructure, which provide benefits to the customers and communities those Utilities serve. Based on its current capital plan, which includes over $10 billion in forecasted capital investments from 2018 through 2023, Regulated Distribution's rate base compounded annual growth rate is expected to be approximately 4% from 2018 through 2023. Additionally, this business is exploring other opportunities for growth, including investments in electric system improvement and modernization projects to increase reliability and improve service to customers, as well as exploring opportunities in customer engagement that focus on the electrification of customers' homes and businesses by providing a full range of products and services.

With approximately 24,500 miles of transmission lines in operation, the Regulated Transmission business is the centerpiece of FirstEnergy's regulated investment strategy with nearly 90% of its capital investments recovered under forward-looking formula rates at the Transmission Companies, and beginning in 2020, JCP&L. Regulated Transmission has also experienced significant growth as part of its Energizing the Future transmission plan with plans to invest over $7 billion in capital from 2018 to 2023, which is expected to result in Regulated Transmission rate base compounded annual growth rate of approximately 10% from 2018 through 2023.

In alignment with FirstEnergy’s strategy to invest in its Regulated Transmission and Regulated Distribution segments as a fully regulated company, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile and maintaining investment grade ratings at its regulated businesses and FE. Specifically, at the regulated businesses, regulatory authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

Any financing plans by FE or any of its 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.

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 the FES Key Creditor Groups against FirstEnergy, and includes the following terms, among others:

- FE will pay certain pre-petition FES Debtors 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 Railway Company/CSX Transportation, Inc. rail settlement guarantee, and the FES Debtors' unfunded pension obligations.
- The nonconsensual release of all claims against FirstEnergy by the FES Debtors' creditors, which was subsequently waived pursuant to the Waiver Agreement, discussed below.
- A $225 million cash payment from FirstEnergy.
- An additional $628 million cash payment from FirstEnergy, 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. On November 21, 2019, FirstEnergy, the FES Debtors, the UCC, and the FES Key Creditors Group entered into an amendment to the settlement agreement, which among other things, changed the $628 million note issuance, into a cash payment to be made upon emergence. The amendment was approved by the Bankruptcy Court on December 16, 2019.
- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continues to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. In addition, FE provides guarantees for certain retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility. On January 21, 2020, AE Supply, FG and a newly formed subsidiary of FG, entered into a letter agreement authorizing the transfer of Pleasants Power Station prior to the FES Debtors’ emergence from bankruptcy. The letter agreement was approved by the Bankruptcy Court on January 28, 2020. The transfer of the Pleasants Power Station was completed on January 30, 2020.
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit for 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.
- Subject to a cap, FirstEnergy has agreed to fund a pension enhancement through its pension plan for voluntary enhanced retirement packages offered to certain FES employees, as well as offer certain other employee benefits (approximately $14 million recognized for the year ending December 31, 2019).
- 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. Based on the 2018 federal tax return filed in September 2019, FirstEnergy owes the FES debtors approximately $31 million associated with 2018, which will be paid upon emergence. Based on current estimates for the 2019 tax return to be filed in 2020, FirstEnergy estimates that it owes the FES Debtors approximately $83 million of which FirstEnergy has paid $14 million as of December 31, 2019. The estimated amounts owed to the FES Debtors for 2018 and 2019 tax returns

excludes amounts allocated for non-deductible interest as discussed in Note 3, "Discontinued Operations." FirstEnergy is currently reconciling tax matters under the Intercompany Tax Allocation Agreement with the FES Debtors.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions. 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, 2019, 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.

2020	**2021-2024**	**Total**
	(In millions)	
$ 364	$ 4,464	$ 4,828

The following table displays consolidated operating lease commitments as of December 31, 2019:

Operating Leases		
		(In millions)
	2020	$ 40
	2021	40
	2022	40
	2023	36
	2024	29
Thereafter		154
Total lease payments		339
Less imputed interest		(66)
Total net present value		$ 273

FE and the Utilities and FET and certain of its subsidiaries participate in two separate five-year syndicated revolving credit facilities providing for aggregate commitments of $3.5 billion, which are available until December 6, 2022. Under the FE credit 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 FET credit 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 FE's transmission subsidiaries.

Borrowings under the credit 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 each of the credit 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 credit facilities contains financial covenants requiring each borrower to maintain a consolidated debt-to-total-capitalization ratio (as defined under each of the credit 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 revolving credit facility described above, including a consolidated debt-to-total-capitalization ratio. Effective September 11, 2019, the two credit agreements noted above were amended to change the amounts available under the existing facilities from $1.25 billion and $500 million to $1 billion and $750 million, respectively, and extend the maturity dates until September 9, 2020, and September 11, 2021, respectively.

The borrowing of $1.75 billion under the 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 $1,000 million and $1,250 million of short-term borrowings as of December 31, 2019 and 2018, respectively. FirstEnergy's available liquidity from external sources as of January 31, 2020, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2022	$ 2,500	$ 2,496
FET[2]	Revolving	December 2022	1,000	1,000
		Subtotal	3,500	3,496
	Cash and cash equivalents		—	465
		Total	$ 3,500	$ 3,961

(1) FE and the Utilities. Available liquidity includes impact of $4 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, 2019, JCP&L, ME and PN had in total approximately $882 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.

On October 15, 2019, JCP&L, ME, PN and GPUN executed an asset purchase and sale agreement with TMI-2 Solutions, LLC, a subsidiary of Energy*Solutions*, LLC, concerning the transfer and dismantlement of TMI-2. This transfer of TMI-2 to TMI-2 Solutions, LLC will include the transfer of: (i) the ownership and operating NRC licenses for TMI-2; (ii) the external trusts for the decommissioning and environmental remediation of TMI-2; and (iii) related liabilities of approximately $900 million as of December 31, 2019. There can be no assurance that the transfer will receive the required regulatory approvals and, even if approved, whether the conditions to the closing of the transfer will be satisfied. On November 12, 2019, JCP&L filed a Petition with the NJBPU seeking approval of the transfer and sale of JCP&L's entire 25% interest in TMI-2 to TMI-2 Solutions, LLC. Also on November 12, 2019, JCP&L, ME, PN, GPUN and TMI-2 Solutions, LLC filed an application with the NRC seeking approval to transfer the NRC license for TMI-2 to TMI-2 Solutions, LLC. Both proceedings are ongoing.

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, hazardous and solid waste disposal, and other environmental matters. While FirstEnergy's environmental policies and procedures are designed to achieve

compliance with applicable environmental laws and regulations, such laws and regulations are subject to periodic review and potential revision by the implementing agencies. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof may materially impact its business, results of operations, cash flows and financial condition.

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. On September 13, 2019, the D.C. Circuit remanded the CSAPR update rule to the EPA citing that the rule did not eliminate upwind states' significant contributions to downwind states' air quality attainment requirements within applicable attainment deadlines. 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 materially impact FirstEnergy's operations, cash flows and financial condition.

In February 2019, the EPA announced its final decision to retain without changes the NAAQS for SO_2, specifically retaining the 2010 primary (health-based) 1-hour standard of 75 PPB. As of September 30, 2019, FirstEnergy has no power plants operating in areas designated as non-attainment by the EPA.

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's 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. On September 20, 2019, the EPA denied New York's CAA Section 126 petition. On October 29, 2019, the State of New York appealed the denial of its petition to the D.C. Circuit. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

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. In 2015, FirstEnergy set a goal of reducing company-wide CO2 emissions by at least 90 percent below 2005 levels by 2045. As of December 31, 2018, FirstEnergy has reduced its CO2 emissions by approximately 62 percent. In September 2016, the U.S. 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's non-binding obligations to limit global warming to 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 CO2 emissions, or litigation alleging damages from GHG emissions, could require material capital and other expenditures or result in changes to its operations.

In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for GHG under the Clean Air Act," 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 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 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. On June 19, 2019, the EPA repealed the CPP and replaced it with the ACE rule that establishes guidelines for states to develop standards of performance to address GHG emissions from existing coal-fired power plants. Depending on the outcomes of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be material.

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 facilities. 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 on September 18, 2017, the EPA postponed certain compliance deadlines for two years. On November 4, 2019, the EPA issued a proposed rule revising the effluent limits for discharges from wet scrubber systems and extending the deadline for compliance to December 31, 2025. The EPA's proposed rule retains the zero discharge standard and 2023 compliance date for ash transport water, but adds some allowances for discharge under certain circumstances. In addition, the EPA allows for less stringent limits for sub-categories of generating units based on capacity utilization, flow volume from the scrubber system, and unit retirement date. 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.

On September 29, 2016, FirstEnergy received a request from the EPA for information pursuant to CWA Section 308(a) for information concerning boron exceedances of effluent limitations established in the NPDES Permit for the former Mitchell Power Station's Mingo landfill, owned by WP. On November 1, 2016, WP provided an initial response that contained information related to a similar boron issue at the former Springdale Power Station's landfill. The EPA requested additional information regarding the Springdale landfill and on November 15, 2016, WP provided a response and intends to fully comply with the Section 308(a) information request. On March 3, 2017, WP proposed to the PA DEP a re-route of its wastewater discharge to eliminate potential boron exceedances at the Springdale landfill. On January 29, 2018, WP submitted an NPDES permit renewal application to PA DEP proposing to re-route its wastewater discharge to eliminate potential boron exceedances at the Mingo landfill. On February 20, 2018, the DOJ issued a letter and tolling agreement on behalf of EPA alleging violations of the CWA at the Mingo landfill while seeking to enter settlement negotiations in lieu of filing a complaint. On November 4, 2019, the EPA proposed a penalty of nearly $1.3 million to settle alleged past boron exceedances at the Mingo and Springdale landfills. On December 17, 2019, WP responded to the EPA's settlement proposal but is unable to predict the outcome of this matter.

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. On November 4, 2019, the EPA issued a proposed rule accelerating the date that certain CCR impoundments must cease accepting waste and initiate closure to August 31, 2020. The proposed rule, which includes a 60-day comment period, provides exceptions, which could allow extensions to closure dates.

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, 2019, 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 $109 million have been accrued through December 31, 2019. Included in the total are accrued liabilities of approximately $77 million for environmental remediation of former MGP 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 7.5 million tons of coal for the year 2020, which is approximately 97.4% of its forecasted 2020 coal requirements. This contracted coal is produced primarily from mines located in Pennsylvania and West Virginia. The contracts expire at various times through 2024. 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	2019	2018	2017
		(in MWs)	
OE	5,494	5,604	5,434
Penn	946	950	926
CEI	4,188	4,301	4,220
TE	2,787	2,367	2,205
JCP&L	6,056	5,977	5,721
ME	2,974	3,026	2,897
PN	3,020	2,993	2,882
MP	2,121	2,089	1,986
PE	3,609	3,498	3,049
WP	4,012	3,879	3,752

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, except for certain customers that are on a decoupled rate. Mild weather conditions may result in lower power sales and consequently lower earnings.

Information About Our Executive Officers (as of February 10, 2020)

Name	Age	Positions Held During Past Five Years	Dates
C. E. Jones	64	President and Chief Executive Officer (A) (B)	2015-present
		Chief Executive Officer (G)	2015-2017
		President (C)	*-2015
C. L. Walker	54	Senior Vice President and Chief Human Resources Officer (B)	2019-present
		Vice President, Human Resources (B)	2018-2019
		Executive Director, Talent Management (B)	2016-2018
		Executive Director, Human Resources (B)	*-2016
G. D. Benz	60	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	*-2015
J. J. Lisowski	38	Vice President, Controller and Chief Accounting Officer (A) (B)	2018-present
		Vice President and Controller (C) (E)	2018-present
		Controller and Treasurer (G)	2017-2018
		Controller and Treasurer (F)	2016-2018
		Assistant Controller (E)	2016-2017
		Assistant Controller (B) (C) (D) (G)	*-2017
		Assistant Controller (A) (F)	*-2016
R. P. Reffner	69	Senior Vice President and General Counsel (A) (B) (C) (E)	2018-present
		Vice President and General Counsel (E)	2016-2018
		Vice President and General Counsel (B) (C)	2015-2018
		Vice President and General Counsel (D)	2015-2017
		Vice President and General Counsel (G)	*-2017
		Vice President and General Counsel (F)	*-2016
S. E. Strah	56	Senior Vice President and Chief Financial Officer (A) (B) (C) (E)	2018-present
		President (D)	2017-2018
		President (E)	2016-2018
		Senior Vice President & President, FirstEnergy Utilities (B)	2015-2018
		President (C)	2015-2018
		Vice President, Distribution Support (B)	*-2015
S. L. Belcher	51	Senior Vice President and President, FirstEnergy Utilities (B)	2018-present
		President (C) (E)	2018-present
		President and Chief Nuclear Officer (G)	2015-2018
		President, FirstEnergy Nuclear Operating Company (B)	2015-2017
		Senior Vice President and Chief Operating Officer (G)	*-2015

* Indicates position held at least since January 1, 2015

(A) Denotes position held at FE

(B) Denotes position held at FESC

(C) Denotes position held at the Ohio Companies, the Pennsylvania Companies, MP, PE, FET, TrAIL and ATSI

(D) Denotes position held at AGC

(E) Denotes position held at MAIT

(F) Denotes position held at FES and FG, which filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code in March 2018

(G) Denotes position held at FENOC, which filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code in March 2018

Employees

As of December 31, 2019, FirstEnergy had 12,316 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	4,632	874
OE	1,128	763
CEI	921	607
TE	348	256
Penn	190	135
JCP&L	1,358	1,058
ME	634	457
PN	754	483
MP	1,094	733
PE	527	329
WP	730	455
Total	**12,316**	**6,150**

As of December 31, 2019, the IBEW, the UWUA and the OPEIU unions collectively represented 5,362 of FirstEnergy’s employees. There are 15 CBAs between FirstEnergy’s subsidiaries and its unions, which have three, four or five year terms. In 2019, FirstEnergy’s subsidiaries reached new agreements with two IBEW locals, covering 468 employees.

FirstEnergy Website 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 website 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 website 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 website and recognizes FirstEnergy’s website as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of postings to the website by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's website. FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under Regulation FD. Information contained on FirstEnergy’s website, 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 and 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 Associated with Regulation

We Have Taken a Series of Actions to Focus on Growing Our Regulated Distribution and Regulated 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

We focus on capitalizing on investment opportunities available to our Regulated Distribution and Regulated 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 and potential impact 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 Distribution and Regulated Transmission operations, and could have a material adverse effect on our regulatory strategy, results of operations and financial condition.

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 results of operations and financial condition.

Complex and Changing Government Regulations and Actions, Including Those Associated with Rates, 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 and financial condition.

Our Utilities and Transmission Companies currently provide service at rates approved by one or more regulatory commissions. Thus, the rates the Utilities and Transmission Companies are 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 applicable 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, if at all. 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.

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, Liquidity, 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 New Jersey by the NJBPU, in Ohio by the PUCO, 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. FERC’s policies on recovery of transmission costs continue to evolve, evidenced by ongoing proceedings to determine an appropriate ROE methodology to determine transmission ROEs and whether FERC’s existing policies on transmission rate incentives should be revised. If FERC were to adopt a different policy regarding recovery of transmission costs 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 adversely impact our financial condition.

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, Which Could Have an Adverse Effect on our Financial Condition

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 that 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 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.

Mandatory Renewable Portfolio Requirements, Energy Efficiency and Peak Demand Reduction Mandates and Energy Price Increases Could Negatively Impact Our Financial Results

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.

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 in certain of our states to recover the cost of these programs either at or near a current recovery time frame in the states where we operate.

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.

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 Business Operations, Cash Flows 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 Related to Climate Change, Could Adversely Affect Cash Flows and Financial Condition

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 GHG Emissions, CWA effluent limitations imposing more stringent water discharge regulations, or other 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. Due to the uncertainty of control technologies available to reduce GHG emissions, any legal obligation that requires substantial reductions of GHG emissions could result in substantial additional costs, adversely affecting cash flows 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 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 addition, there can be no assurance that any liabilities, losses or expenditures we may incur related to such environmental liabilities or contamination will be covered under any applicable insurance policies or that the amount of insurance will be adequate.

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.

The Risks Associated with Climate Change May Have an Adverse Impact on Our Business Operations, Financial Condition 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, financial condition 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.

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, Cash Flows 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, cash flows and financial condition and could significantly impact our business operations.

We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of Our Facilities that May Have an Adverse Impact on our Business Operations, Financial Condition and Cash Flows

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.

Risks Related to Business Operations Generally

Temperature Variations as well as Severe Weather Conditions or other Natural Disasters Could Have an Adverse Impact on Our Results of Operations and Financial Condition

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, high winds 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 from Regional and General Economic Cycles as Well as 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.

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 Results of Operations and Financial Condition May be Adversely Affected by the Volatility in Pension and OPEB Expenses Due to Capital Market Performance and Other Changes

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, such as when the FES Debtors emerge from bankruptcy, resulting in greater volatility in pension and OPEB expenses and may materially impact our results of operations such as when the FES Debtors emerge from bankruptcy.

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.

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, Results of Operations, 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, results of operations, financial condition and reputation.

We Have Coal-Fired Generation Capacity, Which Exposes Us to Risk from Regulations Relating to Coal, GHGs and CCRs and Could Lead to Increased Costs or the Need to Spend Significant Resources to Defend Allegations of Violation

Approximately 82% of FirstEnergy's generation fleet capacity is coal-fired, totaling 3,160 MWs. 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.

Financial Risks Associated with Owning Coal-Fired Generation may have an Adverse Impact on our Business Operations, Financial Condition and Cash Flows

86% of MP's generation fleet, totaling 3,093 MWs, is coal-fired. Recently, certain members of the investment community have adopted investment policies promoting the divestment of coal-fired generation or otherwise limiting new investments in coal-fired generation. The impact of such efforts may adversely affect the demand for and price of our common stock and impact our and MP's access to the capital and financial markets. Further, certain insurance companies have established policies limiting coal-related underwriting and investment. Consequently, these policies aimed at coal-fired generation could have a material adverse impact on our business operations, financial condition, and cash flows.

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, Cash Flows 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, cash flows 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 transmission and distribution, including but not limited to our *Energizing the Future* transmission expansion program, which has been extended to include up to $7.9 billion in investments from 2018 through 2023. We also anticipate spending $1.7 billion per year in distribution capital expenditures from 2018 through 2023. 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.

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

We may use a variety of non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage our 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.

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 results of operations, financial condition and liquidity.

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 and Adversely Affect Our Results of Operations, Cash Flows and Financial Condition

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 $114 million at December 31, 2019. 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 $114 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 the Utilities and Transmission Companies, 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 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 operations, as well as its relationship with its employees, suppliers, customers and other parties, may be materially and adversely impacted by negative or confusing publicity related to the FES Bankruptcy or otherwise. 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, and the FES Debtors, which was subsequentially amended on November 21, 2019 and approved by the Bankruptcy Court on December 16, 2019. 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 not to exceed $853 million in aggregate principal amount; the transfer of AE Supply's Pleasants Power Station; which was completed on January 30, 2020, 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. 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. 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 addition, if the settlement were not consummated, the costs of additional 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.

Certain Events in Connection with the Disposition of Competitive Generation Assets May Significantly Increase Cash Flows 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, which was approved by the Bankruptcy Court on March 7, 2019, to transfer the 1,300 MW Pleasants Power Station and related assets to FG, while retaining certain specified liabilities, which transfer was completed on January 30, 2020. AE Supply will continue to provide access to the McElroy's Run CCR Impoundment Facility, which was not transferred. In addition, FE provides certain guarantees for retained environmental liabilities of AE Supply, including the McElroy's Run CCR Impoundment Facility. 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.

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 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 FirstEnergy or FirstEnergy 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 or execute on our business strategies by substantially increasing the cost of, or limiting access to, capital.

Failure to Comply with Debt Covenants in our Credit Agreements or Conditions Could Adversely Affect our Ability to Execute Future Borrowings and/or Require Early Repayment.

Our debt and credit agreements contain various financial and other covenants including a consolidated debt to total capitalization ratio of no more than 65% measured at the end of each fiscal quarter. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements, which would negatively affect the applicable company's financial condition and liquidity.

The Anticipated Phasing Out of LIBOR after 2021 Could Adversely Affect our Financial Results

A portion of FirstEnergy's indebtedness bears interest at fluctuating interest rates, primarily based on LIBOR. LIBOR tends to fluctuate based on general interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. FirstEnergy has not hedged its interest rate exposure with respect to its floating rate debt. Accordingly, FirstEnergy's interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. On July 27, 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index, calculated based on repurchase agreements backed by treasury securities. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom, the United States or elsewhere. To the extent these interest rates increase, interest expense will increase. If sources of capital for FirstEnergy are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse effect on our results of operations, cash flows, financial condition and liquidity.

We Must Rely on Cash from Our Subsidiaries and Any Restrictions on The Utilities and Transmission Companies' 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, the Utilities and Transmission Companies 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 the Utilities and Transmission Companies to pay dividends or otherwise restrict cash payments to us.

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

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

The Tax Characterization of Our Distributions to Shareholders Will Likely Change

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 FirstEnergy's accumulated E&P may have been exhausted for the 2019 tax year or will be exhausted upon the FES Debtors' emergence from bankruptcy. 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.

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 11, "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, 2019, shown in the table below. Except for the OVEC participation referenced in the footnotes to the table, the Corp/Other units are owned by AE Supply and the Regulated Distribution segment generating units are owned by either JCP&L or MP.

Plant (Location)	Unit	Total		Corp/Other	Regulated Distribution
		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
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 the transfer, which was completed on January 30, 2020, and beginning January 1, 2019, FES acquired the economic interests in Pleasants and AE Supply operated 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 24,486 circuit miles.

The Utilities' electric distribution systems include 269,691 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits.

FirstEnergy owns substations with a total installed transformer capacity of 156,115,196 kV-amperes.

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

FirstEnergy's distribution and transmission systems as of December 31, 2019, consist of the following:

	Distribution Lines[1]	Transmission Lines[1]	Substation Transformer Capacity[2]
			kV Amperes
OE	67,340	379	7,228,811
Penn	13,609	—	915,584
CEI	33,037	—	9,296,048
TE	19,039	73	2,941,606
JCP&L	23,680	2,598	21,375,598
ME	18,983	—	4,804,655
PN	27,670	—	6,828,636
ATSI[3]	—	7,889	37,985,722
WP	24,737	4,331	14,266,148
MP	22,322	2,612	13,314,783
PE	19,274	2,086	10,514,104
TrAIL	—	262	13,643,600
MAIT	—	4,256	12,999,901
Total	269,691	24,486	156,115,196

(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 the Ohio Companies and Penn.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 14, "Regulatory Matters," and Note 15, "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, dividend information, shareholder return 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 2019.

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

ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2019	2018	2017	2016	2015
	(In millions, except per share amounts)				
Revenues	$ 11,035	$ 11,261	$ 10,928	$ 10,700	$ 10,583
Income (Loss) From Continuing Operations	$ 904	$ 1,022	$ (289)	$ 551	$ 383
Net Income (Loss) Attributable to Common Stockholders	$ 908	$ 981	$ (1,724)	$ (6,177)	$ 578
Earnings (Loss) per Share of Common Stock:					
Basic - Continuing Operations	$ 1.69	$ 1.33	$ (0.65)	$ 1.29	$ 0.91
Basic - Discontinued Operations	0.01	0.66	(3.23)	(15.78)	0.46
Basic - Net Income (Loss) Attributable to Common Stockholders	$ 1.70	$ 1.99	$ (3.88)	$ (14.49)	$ 1.37
Diluted - Continuing Operations	$ 1.67	$ 1.33	$ (0.65)	$ 1.29	$ 0.91
Diluted - Discontinued Operations	0.01	0.66	(3.23)	(15.78)	0.46
Diluted - Net Income (Loss) Attributable to Common Stockholders	$ 1.68	$ 1.99	$ (3.88)	$ (14.49)	$ 1.37
Weighted Average Number of Common Shares Outstanding:					
Basic	535	492	444	426	422
Diluted	542	494	444	426	424
Dividends Declared per Share of Common Stock	$ 1.53	$ 1.82	$ 1.44	$ 1.44	$ 1.44

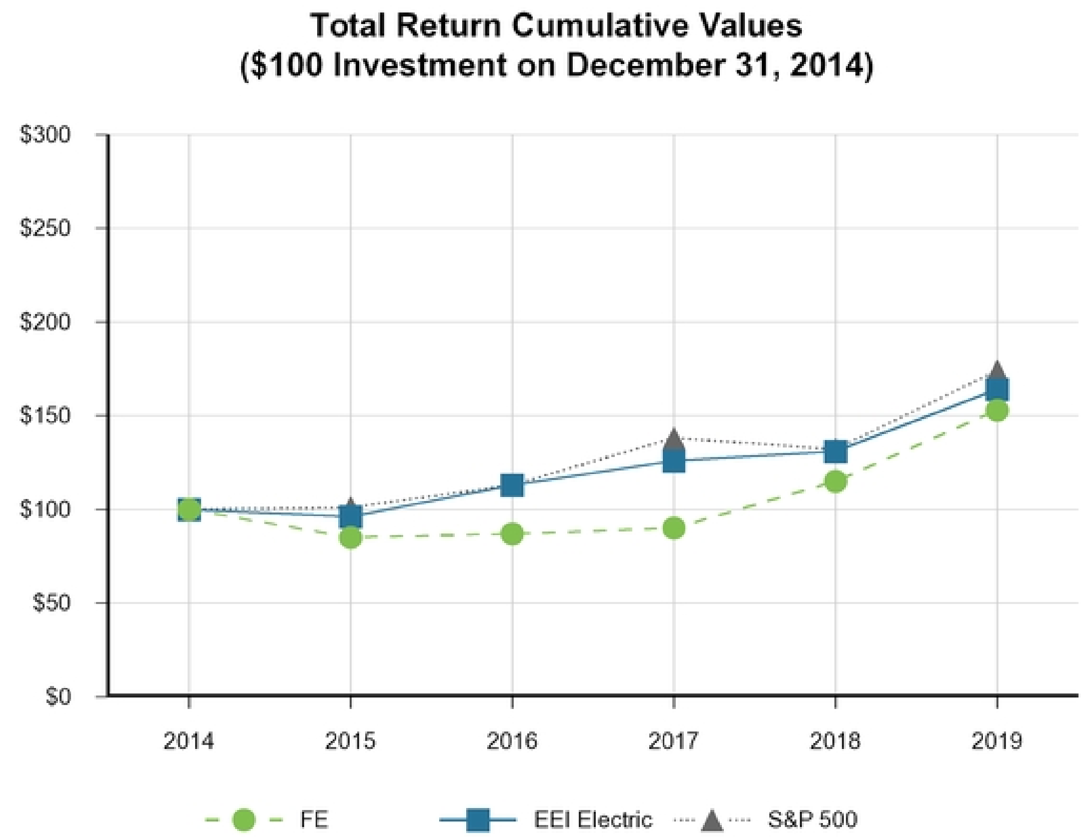
As of December 31,	2019	2018	2017	2016	2015
Total Assets	$ 42,301	$ 40,063	$ 42,257	$ 43,148	$ 52,094
Capitalization:					
Total Equity	$ 6,975	$ 6,814	$ 3,925	$ 6,241	$ 12,422
Long-Term Debt and Other Long-Term Obligations	19,618	17,751	18,687	15,251	16,444
Total Capitalization	$ 26,593	$ 24,565	$ 22,612	$ 21,492	$ 28,866

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, 2014, 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 70,622 holders of 540,652,222 shares of FE’s common stock as of December 31, 2019, and 70,327 holders of 540,713,909 shares of FE's common stock as of January 31, 2020. We have historically paid quarterly cash dividends on our common stock. 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. Information regarding retained earnings available for payment of cash dividends is given in Note 11, "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, including, without limitation, mitigating exposure for remedial activities associated with formerly owned generation assets.
- 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, and to improve our credit metrics, strengthen our balance sheet and grow earnings.
- Legislative and regulatory developments, 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 climate change or 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, which 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 reliability standards and energy efficiency and peak demand reduction mandates.
- Changes to 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 contributions sooner, or in amounts that are larger, than currently anticipated.
- 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 or FENOC or their creditors.
- The risks associated with the decommissioning of our retired and former nuclear facilities.
- 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, 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, including the increasing number of financial institutions evaluating the impact of climate change on their investment decisions.
- 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 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 or in the information incorporated by reference as a result of new information, future events or otherwise.

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, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the 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, 2019, are summarized below (in thousands):

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,055
Penn	Western Pennsylvania	168
CEI	Northeastern Ohio	752
TE	Northwestern Ohio	313
JCP&L	Northern, Western and East Central New Jersey	1,142
ME	Eastern Pennsylvania	575
PN	Western Pennsylvania and Western New York	587
WP	Southwest, South Central and Northern Pennsylvania	729
MP	Northern, Central and Southeastern West Virginia	392
PE	Western Maryland and Eastern West Virginia	419
		6,132

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. Effective January 1, 2020, JPC&L's transmission rates became forward-looking formula rates, subject to refund, pending further hearing and settlement proceedings. 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.

Corporate/Other 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, 2019, 67 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of Corporate/Other. As of December 31, 2019, Corporate/Other had approximately $7.1 billion of FE holding company debt.

EXECUTIVE SUMMARY

FirstEnergy is a forward-thinking fully regulated electric utility focused on stable and predictable earnings and cash flow from its regulated business units - Regulated Distribution and Regulated Transmission - through delivering enhanced customer service and reliability that supports FE's dividend.

In 2019, FirstEnergy continued its significant progress of executing on its regulated growth plans, which included the following achievements:

- MDPSC-approved distribution base rate increase,
- MDPSC-approved EDIS programs,
- NJ BPU-approved JCP&L IIP settlement,
- PUCO-approved Ohio Grid Modernization plan and Tax Reform settlement,
- PUCO-approved Ohio Companies’ decoupling application,
- WVPSC-approved ENEC rates that began January 1, 2020,
- Filed for forward-looking formula rates for JCP&L’s transmission assets,
- Pennsylvania Companies filed LTIIP II plans for 2020-2024, including a DSIC cap increase at Penn to 7.5%, approved in January 2020,
- Signed an agreement to transfer TMI-2 to a subsidiary of Energy*Solutions*, LLC,
- Received credit ratings upgrades from Fitch Ratings at FE and all rated Utility and Transmission subsidiaries,
- Received credit ratings upgrades from Moody's at ATSI, CEI, JCP&L, MAIT, OE, Penn and TE,
- Announced that the FE Board of Directors approved a 3% increase to the dividend payable March 1, 2020, and
- Published a Strategic Plan and a Corporate Responsibility Report as part of our forward-thinking strategy and commitment to ESG issues.

With an operating territory of 65,000 square miles, the scale and diversity of the ten Utilities that comprise the Regulated Distribution business uniquely position this business for growth through opportunities for additional investment. Over the past several years, Regulated Distribution has experienced rate base growth through investments that have improved reliability and added operating flexibility to the distribution infrastructure, which provide benefits to the customers and communities those Utilities serve. Based on its current capital plan, which includes over $10 billion in forecasted capital investments from 2018 through 2023, Regulated Distribution’s rate base compounded annual growth rate is expected to be approximately 4% from 2018 through 2023. Additionally, this business is exploring other opportunities for growth, including investments in electric system improvement and modernization projects to increase reliability and improve service to customers, as well as exploring opportunities in customer engagement that focus on the electrification of customers’ homes and businesses by providing a full range of products and services.

With approximately 24,500 miles of transmission lines in operation, the Regulated Transmission business is the centerpiece of FirstEnergy’s regulated investment strategy with nearly 90% of its capital investments recovered under forward-looking formula rates at the Transmission Companies, and beginning in 2020, JCP&L. Regulated Transmission has also experienced significant growth as part of its Energizing the Future transmission plan with plans to invest over $7 billion in capital from 2018 to 2023, which is expected to result in Regulated Transmission rate base compounded annual growth rate of approximately 10% from 2018 through 2023.

As part of the Energizing the Future initiative, the Center for Advanced Technology was opened in Akron, Ohio in April 2019. The 88,000 square feet facility was designed to be a hands-on environment where engineers and technicians can develop and evaluate new technology and grid solutions and simulate a variety of real-world conditions.

FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of over $20 billion beyond those identified through 2023, 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 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. In November 2019, the Board declared a $0.01 increase to the common dividend payable March 1, 2020, to $0.39 per share, which represents a 3% increase. 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 progressing in its sustainability efforts. In 2019, FirstEnergy's Sustainability group focused on the continued realization of sustainability accomplishments. In November 2019, FirstEnergy's Corporate Responsibility Report was published. The report addresses FirstEnergy's work to reduce the environmental impact of our operations, including progress on our CO_2 reduction goal, as we continue to build, strengthen and modernize our transmission and distribution system. The report also describes FirstEnergy's high standards for corporate governance and our work to improve lives in our communities, while providing safe, reliable electric service to our customers. In 2020, FirstEnergy is focusing on additional initiatives that aim to inform, engage and achieve its sustainability goals, and demonstrate its commitment to stakeholders.

As previously disclosed, 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 equity investment strengthened the Company’s balance sheet, supported the company’s transition to a fully regulated utility company and positions FirstEnergy for sustained investment-grade credit metrics. The shares of preferred stock participated in the dividend paid on common stock on an as-converted basis and were non-voting except in certain limited circumstances. Because of this investment, FirstEnergy does not currently anticipate the need to issue additional equity through 2021 and expects to issue, subject to, among other things, market conditions, pricing terms and business operations, up to $600 million of equity annually in 2022 and 2023, including approximately $100 million in equity for its regular stock investment and employee benefit plans. As of August 1, 2019, an aggregate of 1,616,000 shares of preferred stock had been converted into 58,935,078 shares of common stock, and as a result, there were no shares of preferred stock outstanding as of December 31, 2019.

On March 31, 2018, FirstEnergy's competitive subsidiary the FES Debtors voluntarily filed petitions under Chapter 11 of the Federal Bankruptcy Code with the U.S. Bankruptcy Court. FirstEnergy and its other subsidiaries - including its Utilities and AE Supply - are not part of the filing and are not subject to the Chapter 11 process. The voluntary bankruptcy filings by the FES Debtors represented a significant event in FirstEnergy’s previously announced strategy to exit the competitive generation business and become a fully regulated utility company with a stronger balance sheet, solid cash flows and more predictable earnings. As a result of the bankruptcy filings, as of March 31, 2018, the FES Debtors were deconsolidated from FirstEnergy’s financial statements. Additionally, the operating results of the FES Debtors, as well as BSPC and a portion of AE Supply (including the Pleasants Power Station) that were subject to completed or pending asset sales, collectively representing substantially all of FirstEnergy’s operations that comprised the CES reportable segment, are presented as discontinued operations. Prior periods have been reclassified to conform with such presentation as discontinued operations.

On April 23, 2018, FirstEnergy and the FES Key Creditor Groups reached an agreement in principle to resolve certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and their creditors against FirstEnergy. 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 the FES Key Creditor Groups against FirstEnergy. See below for further discussion on the terms of the settlement agreement.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions. 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.

With the bankruptcy filings of the FES Debtors, the completed sale of the previously announced competitive Bath hydroelectric station, and the completed transfer of the Pleasants Power Station, FirstEnergy’s electric generation fleet is now made up of 3,790 MW of regulated generation, including four plants in West Virginia, Virginia and New Jersey.

The Form 10-K discusses 2019 and 2018 items and year-over-year comparisons between 2019 and 2018. Discussions of 2017 items and year-over-year comparisons between 2018 and 2017 that are not included in this Form 10-K can be found in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Part II, Item 7 of the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2018, filed with the SEC on February 19, 2019.

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 17, "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:

(In millions, except per share amounts)	**For the Years Ended December 31,**			**Increase (Decrease)**	
	2019	**2018**	**2017**	**2019 vs 2018**	**2018 vs 2017**
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 1,076	$ 1,242	$ 916	$ (166)	$ 326
Regulated Transmission	447	397	336	50	61
Corporate/Other	(619)	(617)	(1,541)	(2)	924
Income (Loss) from Continuing Operations	$ 904	$ 1,022	$ (289)	$ (118)	$ 1,311
Discontinued Operations	8	326	(1,435)	(318)	1,761
Net Income (Loss)	$ 912	$ 1,348	$ (1,724)	$ (436)	$ 3,072
Earnings (Loss) per share of common stock					
Basic - Continuing Operations	$ 1.69	$ 1.33	$ (0.65)	$ 0.36	$ 1.98
Basic - Discontinued Operations	0.01	0.66	(3.23)	(0.65)	3.89
Basic - Net Income (Loss) Attributable to Common Stockholders	$ 1.70	$ 1.99	$ (3.88)	$ (0.29)	$ 5.87
Earnings (Loss) per share of common stock					
Diluted - Continuing Operations	$ 1.67	$ 1.33	$ (0.65)	$ 0.34	$ 1.98
Diluted - Discontinued Operations	0.01	0.66	(3.23)	(0.65)	3.89
Diluted - Net Income (Loss) Attributable to Common Stockholders	$ 1.68	$ 1.99	$ (3.88)	$ (0.31)	$ 5.87

Summary of Results of Operations — 2019 Compared with 2018

Financial results for FirstEnergy's business segments for the years ended December 31, 2019 and 2018, were as follows:

2019 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
Electric	$ 9,452	$ 1,510	$ (128)	$ 10,834
Other	246	16	(61)	201
Total Revenues	9,698	1,526	(189)	11,035
Operating Expenses:				
Fuel	497	—	—	497
Purchased power	2,910	—	17	2,927
Other operating expenses	2,836	272	(156)	2,952
Provision for depreciation	863	284	73	1,220
Amortization (deferral) of regulatory assets, net	(89)	10	—	(79)
General taxes	760	209	39	1,008
Total Operating Expenses	7,777	775	(27)	8,525
Operating Income (Loss)	1,921	751	(162)	2,510
Other Income (Expense):				
Miscellaneous income, net	174	15	54	243
Pension and OPEB mark-to-market adjustment	(290)	(47)	(337)	(674)
Interest expense	(495)	(192)	(346)	(1,033)
Capitalized financing costs	37	33	1	71
Total Other Expense	(574)	(191)	(628)	(1,393)
Income (Loss) Before Income Taxes (Benefits)	1,347	560	(790)	1,117
Income taxes (benefits)	271	113	(171)	213
Income (Loss) From Continuing Operations	1,076	447	(619)	904
Discontinued Operations, net of tax	—	—	8	8
Net Income (Loss)	$ 1,076	$ 447	$ (611)	$ 912

2018 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
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 (benefits)	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

Changes Between 2019 and 2018 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
Electric	$ (399)	$ 175	$ 8	$ (216)
Other	(6)	(2)	(2)	(10)
Total Revenues	(405)	173	6	(226)
Operating Expenses:				
Fuel	(41)	—	—	(41)
Purchased power	(193)	—	11	(182)
Other operating expenses	(148)	19	(52)	(181)
Provision for depreciation	51	32	1	84
Amortization (deferral) of regulatory assets, net	74	(3)	—	71
General taxes	—	17	(2)	15
Total Operating Expenses	(257)	65	(42)	(234)
Operating Income (Loss)	(148)	108	48	8
Other Income (Expense):				
Miscellaneous income (expense), net	(18)	1	55	38
Pension and OPEB mark-to-market adjustment	(181)	(39)	(310)	(530)
Interest expense	19	(25)	89	83
Capitalized financing costs	11	(4)	(1)	6
Total Other Expense	(169)	(67)	(167)	(403)
Income (Loss) Before Income Taxes (Benefits)	(317)	41	(119)	(395)
Income taxes (benefits)	(151)	(9)	(117)	(277)
Income (Loss) From Continuing Operations	(166)	50	(2)	(118)
Discontinued Operations, net of tax	—	—	(318)	(318)
Net Income (Loss)	$ (166)	$ 50	$ (320)	$ (436)

Regulated Distribution — 2019 Compared with 2018

Regulated Distribution's net income decreased $166 million in 2019, as compared to 2018, primarily resulting from the SCOH ruling that ceased collection of Rider DMR, a higher pension and OPEB mark-to-market adjustment, the absence of the reversal of a reserve on recoverability of certain REC purchases in Ohio, and lower revenues associated with decreased weather-related usage.

Revenues —

The $405 million decrease in total revenues resulted from the following sources:

	For the Years Ended December 31,		
Revenues by Type of Service	**2019**	**2018**	**Decrease**
		(In millions)	
Distribution services [1]	$ 5,314	$ 5,413	$ (99)
Generation sales:			
Retail	3,727	3,936	(209)
Wholesale	411	502	(91)
Total generation sales	4,138	4,438	(300)
Other	246	252	(6)
Total Revenues	$ 9,698	$ 10,103	$ (405)

[1] Includes $181 million and $254 million of ARP revenues for the years ended December 31, 2019 and 2018, respectively.

Distribution services revenues decreased $99 million in 2019, as compared to 2018, primarily resulting from the SCOH ruling that ceased collection of Rider DMR, lower weather-related customer usage, and the implementation of rate orders and settlements related to the Tax Act, partially offset by implementation of NJ Zero Emission Program in June 2019 and higher rates associated with the recovery of deferred costs. Distribution deliveries by customer class are summarized in the following table:

	For the Years Ended December 31,		
Electric Distribution MWH Deliveries	**2019**	**2018**	**Decrease**
	(In thousands)		
Residential	54,159	55,994	(3.3)%
Commercial	37,330	38,605	(3.3)%
Industrial	55,649	56,611	(1.7)%
Other	558	560	(0.4)%
Total Electric Distribution MWH Deliveries	147,696	151,770	(2.7)%

Lower distribution deliveries to residential and commercial customers primarily reflect lower weather-related usage resulting from cooling degree days that were 16% below 2018, but 16% above normal, as well as, heating degree days that were 5% below 2018, and 4% below normal. Deliveries to industrial customers reflect lower steel and automotive customer usage, partially offset by higher shale customer usage.

The following table summarizes the price and volume factors contributing to the $300 million decrease in generation revenues in 2019, as compared to 2018:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (2)
Change in prices	(207)
	(209)
Wholesale:	
Effect of increase in sales volumes	2
Change in prices	(51)
Capacity revenue	(42)
	(91)
Decrease in Generation Revenues	$ (300)

Total generation provided by alternative suppliers as a percentage of total MWH deliveries was flat. The decrease in retail generation prices primarily resulted from lower non-shopping generation auction rates across all service territories and a lower ENEC rate in West Virginia, which included rate reductions resulting from the Tax Act.

Wholesale generation revenues decreased $91 million in 2019, as compared to 2018, primarily due to lower spot market energy prices and capacity revenue. 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 decreased $257 million primarily due to the following:

- Fuel expense decreased $41 million in 2019, as compared to 2018, primarily due to lower unit costs.

- Purchased power costs decreased $193 million in 2019, as compared to 2018, primarily due to lower unit costs and capacity expense, partially offset by the implementation of the NJ Zero Emission Program in June 2019.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (82)
Change due to increased volumes	89
	7
Purchases from affiliates:	
Change due to decreased unit costs	(9)
Change due to decreased volumes	(138)
	(147)
Capacity expense	(53)
Decrease in Purchased Power Costs	$ (193)

- Other operating expenses decreased $148 million primarily due to:

    - Decreased storm restoration costs of $129 million, which were mostly deferred for future recovery, resulting in no material impact on current period earnings.
    - Lower operating and maintenance expenses of $49 million, primarily associated with lower employee benefits and corporate support costs.
    - Decreased expenses due to transactions now accounted for as finance leases of $21 million. As a result of the adoption of the new lease accounting standard, financing lease expenses that were recognized in other operating expenses are now recognized in depreciation and interest expense.
    - The absence of $30 million in costs that occurred in 2018 associated with the voluntary enhanced retirement program.
    - Lower energy efficiency and other program costs of $27 million, partially offset by higher vegetation management spend of $13 million. These costs are deferred for future recovery, resulting in no material impact on current period earnings.
    - Higher network transmission expenses of $95 million reflecting increased transmission costs as well as the absence of the FERC settlement during 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 recognized in 2018, 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.

- Depreciation expense increased $51 million, primarily due to a higher asset base and transactions now accounted for as finance leases, as discussed above.

- Net amortization expense increased $74 million, primarily due to decreased storm restoration cost deferrals, the absence of the reversal of a liability at the Ohio Companies for an Ohio Supreme Court ruling regarding the purchase of RECs, partially offset by higher deferrals of generation and transmission expenses, including the FERC settlement discussed above and the termination of the Morgantown Energy Associates PPA.

Other Expense —

Total other expense increased $169 million, primarily due to an increase in the 2019 pension and OPEB mark-to-market adjustment, higher net pension and OPEB non-service costs, and transactions now accounted for as finance leases, as discussed above. This was partially offset by lower interest expense resulting from activities related to debt maturities and refinancing and higher capitalized financing costs. The 2019 mark-to-market adjustment resulted from a decrease in the discount rate used to measure benefit obligations, partially offset by higher than expected asset returns.

Income Taxes

Regulated Distribution’s effective tax rate was 20.1% and 25.4% for 2019 and 2018, respectively. The lower effective tax rate in 2019 was primarily due the amortization of net excess deferred income taxes resulting from Tax Act settlements and orders with certain regulatory commissions.

Regulated Transmission — 2019 Compared with 2018

Regulated Transmission's operating results increased $50 million in 2019, as compared to 2018, primarily resulting from the impact of a higher rate base at ATSI and MAIT, partially offset by a lower rate base at TrAIL.

Revenues —

Total revenues increased $173 million in 2019, as compared to 2018, primarily due to higher rate base at ATSI and MAIT and the recovery of incremental expenses at the formula rate companies, partially offset by a lower rate base at TrAIL.

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

	For the Years Ended December 31,		
Revenues by Transmission Asset Owner	**2019**	**2018**	**Increase**
		(In millions)	
ATSI	$ 758	$ 668	$ 90
TrAIL	251	246	5
MAIT	227	154	73
Other	290	285	5
Total Revenues	$ 1,526	$ 1,353	$ 173

Operating Expenses —

Total operating expenses increased $65 million in 2019, as compared to 2018, 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 ATSI and MAIT, resulting in no material impact on current period earnings.

Other Expense —

Total other expense increased $67 million in 2019, as compared to 2018, primarily due to an increase in the 2019 pension and OPEB mark-to-market adjustment and higher interest expense associated with new debt issuances at ATSI, MAIT and FET. The 2019 mark-to-market adjustment resulted from a decrease in the discount rate used to measure benefit obligations partially offset by higher than expected asset returns.

Income Taxes —

Regulated Transmission's effective tax rate was 20.2% and 23.5% for 2019 and 2018, respectively. The lower effective tax rate was primarily due to the amortization of net excess deferred income taxes resulting from FERC guidance related to the Tax Act.

Corporate/Other — 2019 Compared with 2018

Financial results from Corporate/Other and reconciling adjustments resulted in a $2 million decrease in income from continuing operations for 2019 compared to 2018, primarily due to a $310 million increase in the 2019 pension and OPEB mark-to-market adjustment. This was partially offset by lower income taxes from the absence of a $126 million charge in the first quarter of 2018 associated with the remeasurement of state deferred taxes in West Virginia when the FES Debtors were removed from the unitary group following their bankruptcy filing on March 31, 2018, lower interest expense of $89 million due to the absence of make-whole payments, and lower other operating expenses of $42 million primarily due to lower incurred corporate support costs in continuing operations related to the FES Debtors and the absence of remeasuring the ARO of McElroy's Run. Although the operations of the FES Debtors for the first quarter of 2018 (prior to deconsolidation on March 31, 2018) are reflected as discontinued operations, certain allocated corporate support costs to the FES Debtors continue to be reflected in continuing operations. Additionally, higher net miscellaneous income was primarily due to higher returns on certain equity method investments and lower non-operating expenses.

For the years ended December 31, 2019 and 2018, FirstEnergy recorded income from discontinued operations, net of tax, of $8 million and $326 million, respectively. The change in discontinued operations, net of tax was primarily due to the absence of a $435 million gain on deconsolidation of FES and FENOC.

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.

As previously disclosed, 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 equity investment strengthened the Company's balance sheet, supported the company's transition to a fully regulated utility company and positions FirstEnergy for sustained investment-grade credit metrics. The shares of preferred stock participated in the dividend paid on common stock on an as-converted basis and were non-voting except in certain limited circumstances. Because of this investment, FirstEnergy does not currently anticipate the need to issue additional equity through 2021 and expects to issue, subject to, among other things, market conditions, pricing terms and business operations, up to $600 million of equity annually in 2022 and 2023, including approximately $100 million in equity for its regular stock investment and employee benefit plans. As of August 1, 2019, an aggregate of 1,616,000 shares of preferred stock had been converted into 58,935,078 shares of common stock, and as a result, there were no shares of preferred stock outstanding as of December 31, 2019.

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 2020 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 by FE and certain of its 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.

On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. FirstEnergy expects no required contributions through 2021.

As part of the Energizing the Future initiative, the Center for Advanced Technology was opened in Akron, Ohio in April 2019. The 88,000 square feet facility was designed to be a hands-on environment where engineers and technicians can develop and evaluate new technology and grid solutions and simulate a variety of real-world conditions.

With an operating territory of 65,000 square miles, the scale and diversity of the ten Utilities that comprise the Regulated Distribution business uniquely position this business for growth through opportunities for additional investment. Over the past several years, Regulated Distribution has experienced rate base growth through investments that have improved reliability and added operating flexibility to the distribution infrastructure, which provide benefits to the customers and communities those Utilities serve. Based on its current capital plan, which includes over $10 billion in forecasted capital investments from 2018 through 2023, Regulated Distribution's rate base compounded annual growth rate is expected to be approximately 4% from 2018 through 2023. Additionally, this business is exploring other opportunities for growth, including investments in electric system improvement and modernization projects to increase reliability and improve service to customers, as well as exploring opportunities in customer engagement that focus on the electrification of customers' homes and businesses by providing a full range of products and services.

Capital expenditures for 2018 and 2019 and forecasted expenditures for 2020, 2021, 2022, and 2023, by reportable segment are included below:

Reportable Segment	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
				(In millions)		
Regulated Distribution	$ 1,635	$ 1,698	$ 1,700	$ 1,700	$ 1,700	$ 1,700
Regulated Transmission	1,165	1,189	1,200	1,200 - 1,450	1,200 - 1,450	1,200 - 1,450
Corporate/Other	183	105	90	110	110	110
Total	$ 2,983	$ 2,992	$ 2,990	$ 3,010 - 3,260	$ 3,010 - 3,260	$ 3,010 - 3,260

FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of over $20 billion beyond those identified through 2023, 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 alignment with FirstEnergy's strategy to invest in its Regulated Transmission and Regulated Distribution segments as a fully regulated company, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile and maintaining investment grade ratings at its regulated businesses and FE. Specifically, at the regulated businesses, regulatory authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

Any financing plans by FE or any of its 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.

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 the FES Key Creditor Groups against FirstEnergy, and includes the following terms, among others:

- FE will pay certain pre-petition FES Debtors 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 Railway Company/CSX Transportation, Inc. rail settlement guarantee, and the FES Debtors' unfunded pension obligations.
- The nonconsensual release of all claims against FirstEnergy by the FES Debtors' creditors, which was subsequently waived pursuant to the Waiver Agreement, discussed below.
- A $225 million cash payment from FirstEnergy.
- An additional $628 million cash payment from FirstEnergy, 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. On November 21, 2019, FirstEnergy, the FES Debtors, the UCC, and the FES Key Creditors Group entered into an amendment to the settlement agreement, which among other things, changed the $628 million note issuance, into a cash payment to be made upon emergence. The amendment was approved by the Bankruptcy Court on December 16, 2019.
- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continues to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. In addition, FE provides guarantees for certain retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility. On January 21, 2020, AE Supply, FG and a newly formed subsidiary of FG, entered into a letter agreement authorizing the transfer of Pleasants Power Station prior to the FES Debtors’ emergence from bankruptcy. The letter agreement was approved by the Bankruptcy Court on January 28, 2020. The transfer of the Pleasants Power Station was completed on January 30, 2020.
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit for 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.
- Subject to a cap, FirstEnergy has agreed to fund a pension enhancement through its pension plan for voluntary enhanced retirement packages offered to certain FES employees, as well as offer certain other employee benefits (approximately $14 million recognized for the year ending December 31, 2019).
- 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. Based on the 2018 federal tax return filed in September 2019, FirstEnergy owes the FES debtors approximately $31 million associated with 2018, which will be paid upon emergence. Based on current estimates for the 2019 tax return to be filed in 2020, FirstEnergy estimates that it owes the FES Debtors approximately $83 million of which FirstEnergy has paid $14 million as of December 31, 2019. The estimated amounts owed to the FES Debtors for 2018 and 2019 tax returns excludes amounts allocated for non-deductible interest as discussed in Note 3, "Discontinued Operations." FirstEnergy is currently reconciling tax matters under the Intercompany Tax Allocation Agreement with the FES Debtors.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions. 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.

As of December 31, 2019, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to short-term borrowings of $1.0 billion, accounts payable of $918 million, current payable long-term debt of $380 million, and other current liabilities of $1.4 billion primarily attributable to customer deposits and anticipated payments under the FES Bankruptcy settlement. Currently payable long-term debt as of December 31, 2019, consistent of the following:

Currently Payable Long-Term Debt	December 31, 2019
	(In millions)
Unsecured notes	$ 250
Secured notes	50
Sinking fund requirements	64
Other notes	16
	$ 380

FirstEnergy believes its cash from operations and available liquidity will be sufficient to meet its working capital needs.

Short-Term Borrowings / Revolving Credit Facilities

FE and the Utilities and FET and certain of its subsidiaries participate in two separate five-year syndicated revolving credit facilities providing for aggregate commitments of $3.5 billion, which are available until December 6, 2022. Under the FE credit 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 FET credit 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 FE's transmission subsidiaries.

Borrowings under the credit 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 each of the credit 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 credit facilities contains financial covenants requiring each borrower to maintain a consolidated debt-to-total-capitalization ratio (as defined under each of the credit facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

FirstEnergy had $1.0 billion and $1.25 billion of short-term borrowings as of December 31, 2019 and 2018, respectively. FirstEnergy's available liquidity from external sources as of January 31, 2020, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2022	$ 2,500	$ 2,496
FET[2]	Revolving	December 2022	1,000	1,000
		Subtotal	$ 3,500	$ 3,496
	Cash and cash equivalents		—	465
		Total	$ 3,500	$ 3,961

(1) FE and the Utilities. Available liquidity includes impact of $4 million of LOCs issued under various terms.
(2) Includes FET and the Transmission Companies.

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, 2020:

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.

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

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in “pricing grids,” whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds. 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, 2019, the borrowers were in compliance with the applicable debt-to-total-capitalization ratio 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 revolving credit facility described above, including a consolidated debt-to-total-capitalization ratio. Effective September 11, 2019, the two credit agreements noted above were amended to change the amounts available under the existing facilities from $1.25 billion and $500 million to $1 billion and $750 million, respectively, and extend the maturity dates until September 9, 2020, and September 11, 2021, respectively.

The borrowing of $1.75 billion under the 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.

A portion of FirstEnergy's indebtedness bears interest at fluctuating interest rates, primarily based on LIBOR. LIBOR tends to fluctuate based on general interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. FirstEnergy has not hedged its interest rate exposure with respect to its floating rate debt. Accordingly, FirstEnergy's interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. On July 27, 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index, calculated based on repurchase agreements backed by treasury securities. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom, the United States or elsewhere. To the extent these interest rates increase, interest expense will increase. If sources of capital for FirstEnergy are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse effect on our results of operations, cash flows, financial condition and liquidity.

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 2019 was 2.27% per annum for the regulated companies' money pool and 2.74% per annum for the unregulated companies' money pool.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of February 6, 2020:

	Corporate Credit Rating			Senior Secured			Senior Unsecured			Outlook [1]		
Issuer	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**
FE	BBB	Baa3	BBB	—	—	—	BBB-	Baa3	BBB	S	S	S
AGC	BBB-	Baa2	BBB	—	—	—	—	—	—	S	S	S
ATSI	BBB	A3	BBB+	—	—	—	BBB	A3	A-	S	S	S
CEI	BBB	Baa2	BBB+	A-	A3	A	BBB	Baa2	A-	S	S	S
FET	BBB	Baa2	BBB	—	—	—	BBB-	Baa2	BBB	S	S	S
JCP&L	BBB	Baa1	BBB+	—	—	—	BBB	Baa1	A-	S	P	S
ME	BBB	A3	BBB+	—	—	—	BBB	A3	A-	S	S	S
MAIT	BBB	A3	BBB+	—	—	—	BBB	A3	A-	S	S	S
MP	BBB	Baa2	BBB	A-	A3	A-	BBB	Baa2	—	S	S	S
OE	BBB	A3	BBB+	A-	A1	A	BBB	A3	A-	S	P	S
PN	BBB	Baa1	BBB+	—	—	—	BBB	Baa1	A-	S	S	S
Penn	BBB	A3	BBB+	—	A1	A	—	—	—	S	P	S
PE	BBB	Baa2	BBB	—	—	A-	—	—	—	S	S	S
TE	BBB	Baa1	BBB+	A-	A2	A	—	—	—	S	S	S
TrAIL	BBB	A3	BBB+	—	—	—	BBB	A3	A-	S	S	S
WP	BBB	A3	BBB+	—	—	A	—	—	—	S	S	S

[1] S = Stable and P = Positive

On March 21, 2019, Moody's upgraded the Senior Unsecured and Issuer ratings of ATSI and MAIT to A3 from Baa1. At the same time, Moody's affirmed the Senior Unsecured and Issuer ratings of their intermediate holding company, FET, at Baa2 as well as TrAIL at A3. The rating outlooks of these companies are stable.

On March 27, 2019, Moody’s upgraded JCP&L’s Senior Unsecured and Issuer ratings to Baa1 from Baa2, and maintained the positive outlook pending the outcome of the Reliability Plus infrastructure investment program.

On April 17, 2019, Fitch upgraded JCP&L’s Issuer rating to BBB from BBB- and its Senior Unsecured rating to BBB+ from BBB with a positive outlook. Also, on April 17, 2019, Fitch upgraded MP, AGC, and PE’s Issuer ratings to BBB from BBB- and the Senior Secured ratings of MP and PE to A- from BBB+ with a stable outlook for MP, AGC and PE and affirmed FE’s and all other FE subsidiaries ratings and positive outlooks.

On July 23, 2019, Moody’s upgraded the Senior Unsecured and Issuer ratings of OE and Penn to A3 from Baa1, TE to Baa1 from Baa3, and CEI to Baa2 from Baa3. The secured ratings for OE and Penn were changed to A1 from A2, TE to A2 from Baa1, and CEI to A3 from Baa1. The rating outlook for OE remains positive, Penn was revised to positive, and TE and CEI were revised to stable.

On November 8, 2019, Fitch upgraded the Corporate Credit Ratings and Senior Unsecured Ratings of FE and FET to BBB from BBB-. The Corporate Credit Ratings of ATSI, CEI, JCP&L, ME, MAIT, OE, PN, Penn, TE, TrAIL, and WP were upgraded to BBB+ from BBB, and the Senior Unsecured Ratings of ATSI, CEI, JCP&L, ME, MAIT, OE, PN, and TrAIL were upgraded to A- from BBB+. Additionally, the Senior Secured Ratings of CEI, OE, Penn, TE, and WP were upgraded to A from A-. At the same time, the Outlook for each of the companies upgraded was changed to Stable from Positive.

Debt capacity is subject to the consolidated debt-to-total-capitalization limits in the credit facilities previously discussed. As of December 31, 2019, FE and its subsidiaries could issue additional debt of approximately $7.8 billion, or incur a $4.2 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, 2019, FirstEnergy had $627 million of cash and cash equivalents and approximately $52 million of restricted cash compared to $367 million of cash and cash equivalents and approximately $62 million of restricted cash as of December 31, 2018, on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's most significant sources of cash are derived from electric service provided by its 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 materials and services.

Net cash provided from operating activities was $2,467 million during 2019, $1,410 million during 2018 and $3,808 million during 2017.

2019 compared with 2018

Cash flows from operations increased $1,057 million in 2019 as compared with 2018. The year-over-year change in cash from operations increased due to the following:

- a $750 million decrease in cash contributions to the qualified pension plan;
- higher transmission revenue reflecting a higher base rate and recovery of incremental operating expenses at ATSI and MAIT;
- decrease to working capital primarily due to higher receipts from customers;
- lower storm costs; partially offset by
- lower revenues due to tax savings being provided to customers in relation to the Tax Act;
- the absence of FES' cash from operations from the first quarter of 2018.

FirstEnergy's Consolidated Statements of Cash Flows combine cash flows from discontinued operations with cash flows from continuing operations within each cash flow category. The following table summarizes the major classes of operating cash flow items from discontinued operations for the years ended December 31, 2019, 2018 and 2017:

	For the Years Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income (loss) from discontinued operations	$ 8	$ 326	$ (1,435)
Gain on disposal, net of tax	(59)	(435)	—
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	—	110	333
Deferred income taxes and investment tax credits, net	47	61	(842)
Unrealized (gain) loss on derivative transactions	—	(10)	81

Cash Flows From Financing Activities

Cash provided from financing activities was $656 million and $1,394 million in 2019 and 2018, respectively, compared to cash used for financing activities of $702 million in 2017. The following table summarizes new equity and debt financing, redemptions, repayments, make-whole premiums paid on debt redemptions short-term borrowings and dividends:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Repaid	**2019**	**2018**	**2017**
		(In millions)	
New Issues			
Preferred stock issuance	$ —	$ 1,616	$ —
Common stock issuance	—	850	—
Unsecured notes	1,850	850	3,800
PCRBs	—	74	—
FMBs	450	50	625
Term loan	—	500	250
	$ 2,300	$ 3,940	$ 4,675
Redemptions / Repayments			
Unsecured notes	$ (725)	$ (555)	$ (1,330)
PCRBs	—	(216)	(158)
FMBs	(1)	(325)	(725)
Term loan	—	(1,450)	—
Senior secured notes	(63)	(62)	(78)
	$ (789)	$ (2,608)	$ (2,291)
Tender premiums paid on debt redemptions	$ —	$ (89)	$ —
Short-term borrowings (repayments), net	$ —	$ 950	$ (2,375)
Preferred stock dividend payments	$ (6)	$ (61)	$ —
Common stock dividend payments	$ (814)	$ (711)	$ (639)

On January 10, 2019, ME issued $500 million of 4.30% senior notes due 2029. Proceeds from the issuance of senior notes were primarily used to refinance existing indebtedness, including ME’s $300 million of 7.70% senior notes due 2019, and borrowings outstanding under the FE regulated utility money pool and the FE Facility, 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 primarily used to refinance existing indebtedness, including amounts outstanding under the FE regulated utility money pool incurred in connection with the repayment at maturity of JCP&L's $300 million of 7.35% senior notes due 2019 and the funding of storm recovery and restoration costs and expenses, to fund capital expenditures and working capital requirements and for other general corporate purposes.

On March 28, 2019, FET issued $500 million of 4.55% senior notes due 2049. Proceeds from the issuance of the senior notes were used primarily to support FET's capital structure, to repay short-term borrowings outstanding under the FE unregulated money pool, to finance capital improvements, and for other general corporate purposes, including funding working capital needs and day-to-day operations.

On April 15, 2019, ATSI issued $100 million of 4.38% senior notes due 2031. Proceeds from the issuance of the senior notes were used primarily to repay short-term borrowings, to fund capital expenditures and working capital needs, and for other general corporate purposes.

On May 21, 2019, WP issued $100 million of 4.22% FMBs due 2059. Proceeds from the issuance of the FMBs were or are, as the case may be, used to refinance existing indebtedness, to fund capital expenditures, and for other general corporate purposes.

On June 3, 2019, PN issued $300 million of 3.60% senior notes due 2029. Proceeds from the issuance of the senior notes were used to refinance existing indebtedness, including amounts outstanding under the FE regulated companies' money pool incurred in connection with the repayment at maturity of PN's $125 million of 6.63% senior notes due 2019, to fund capital expenditures, and for other general corporate purposes.

On June 5, 2019, AGC issued $50 million of 4.47% senior unsecured notes due 2029. Proceeds from the issuance of the senior notes were used to improve liquidity, re-establish the debt component within its capital structure following the recent redemption of all of its existing long-term debt, and satisfy working capital requirements and other general corporate purposes.

On August 15, 2019, WP issued $150 million of 4.22% FMBs due 2059. Proceeds were used to refinance existing indebtedness, fund capital expenditures and for other general corporate purposes.

On November 14, 2019, MP issued $155 million of 3.23% FMBs due 2029 and $45 million of 3.93% FMBs due 2049. Proceeds were used to refinance existing debt, to fund capital expenditures, and for other general corporate purposes.

Cash Flows From Investing Activities

Cash used for investing activities in 2019 principally represented cash used for property additions. The following table summarizes investing activities for 2019, 2018 and 2017:

	For the Years Ended December 31,		
Cash Used for Investing Activities	**2019**	**2018**	**2017**
		(In millions)	
Property Additions:			
Regulated Distribution	$ 1,473	$ 1,411	$ 1,191
Regulated Transmission	1,090	1,104	1,030
Corporate/Other	102	160	366
Nuclear fuel	—	—	254
Proceeds from asset sales	(47)	(425)	(388)
Investments	38	54	98
Notes receivable from affiliated companies	—	500	—
Asset removal costs	217	218	172
Other	—	(4)	—
	$ 2,873	$ 3,018	$ 2,723

2019 compared with 2018

Cash used for investing activities in 2019 decreased $145 million compared to 2018, primarily due to the decrease in notes receivable from affiliated companies resulting from FES's borrowings from the committed line of credit available under the secured credit facility with FE during the first quarter of 2018 and investments, partially offset by lower proceeds from asset sales.

FirstEnergy's Consolidated Statements of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each cash flow category. The following table summarizes the major classes of investing cash flow items from discontinued operations for the years ended December 31, 2019, 2018 and 2017:

	For the Years Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	$ —	$ (27)	$ (317)
Nuclear fuel	—	—	(254)
Sales of investment securities held in trusts	—	109	940
Purchases of investment securities held in trusts	—	(122)	(999)

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.

Management assesses the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. Management applies judgment in evaluating the evidence available to assess the probability of recovery of regulatory assets from customers, including, but not limited to evaluating evidence related to precedent for similar items at the Company and information on comparable companies within similar jurisdictions, as well as assessing progress of communications between the Company and regulators. Certain of these regulatory assets, totaling approximately $111 million as of December 31, 2019, are recorded based on prior precedent or anticipated recovery based on rate making premises without a specific order.

The following table provides information about the composition of net regulatory assets and liabilities as of December 31, 2019 and December 31, 2018, and the changes during the year ended December 31, 2019:

Net Regulatory Assets (Liabilities) by Source	**December 31, 2019**	**December 31, 2018**	**Change**
		(In millions)	
Regulatory transition costs	$ (8)	$ 49	$ (57)
Customer payables for future income taxes	(2,605)	(2,725)	120
Nuclear decommissioning and spent fuel disposal costs	(197)	(148)	(49)
Asset removal costs	(756)	(787)	31
Deferred transmission costs	298	170	128
Deferred generation costs	214	202	12
Deferred distribution costs	155	208	(53)
Contract valuations	51	72	(21)
Storm-related costs	551	500	51
Other	36	52	(16)
Net Regulatory Liabilities included on the Consolidated Balance Sheets	$ (2,261)	$ (2,407)	$ 146

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

Regulatory transition costs - Includes the recovery of PN above-market NUG costs; 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 BGS, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market. Amounts are amortized primarily 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 assets reverse, which is generally over the expected life of the underlying asset.

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) primarily for the future decommissioning of TMI-2.

Asset removal costs - Primarily represents the rates charged to customers that include a provision for the cost of future activities to remove assets, including obligations for which an ARO 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 the formula-rate 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 - Includes the changes in fair value of PN above-market NUG costs and the amortization of purchase accounting adjustments at MP and PE which were 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 2034 through 2036).

Storm-related costs - Relates to the recovery of storm costs, which vary by jurisdiction. Approximately $193 million and $232 million are currently being recovered through rates as of December 31, 2019 and 2018, respectively.

The following table provides information about the composition of net regulatory assets that do not earn a current return as of December 31, 2019 and 2018, of which approximately $228 million and $290 million, respectively, are currently being recovered through rates over varying periods depending on the nature of the deferral and the jurisdiction.

Regulatory Assets by Source Not Earning a Current Return	**December 31, 2019**	**December 31, 2018**	**Change**
		(in millions)	
Regulatory transition costs	$ 7	$ 10	$ (3)
Deferred transmission costs	27	80	(53)
Deferred generation costs	15	8	7
Storm-related costs	471	363	108
Other	25	42	(17)
Regulatory Assets Not Earning a Current Return	$ 545	$ 503	$ 42

CONTRACTUAL OBLIGATIONS

As of December 31, 2019, FirstEnergy's estimated undiscounted cash payments under existing contractual obligations that it considers firm obligations are as follows:

Contractual Obligations	Total	2020	2021-2022	2023-2024	Thereafter
			(In millions)		
Long-term debt[1]	$ 20,066	$ 364	$ 2,024	$ 2,440	$ 15,238
Short-term borrowings	1,000	1,000	—	—	—
Interest on long-term debt[2]	12,131	928	1,781	1,581	7,841
Operating leases[3]	339	40	80	65	154
Finance leases[3]	80	20	32	12	16
Fuel and purchased power[4]	1,687	540	770	377	—
Capital expenditures[5]	1,445	503	573	369	—
Pension funding	1,385	—	159	721	505
FES bankruptcy settlement agreement[6]	853	853	—	—	—
Intercompany tax allocation agreement[7]	100	100	—	—	—
Total	$ 39,086	$ 4,348	$ 5,419	$ 5,565	$ 23,754

(1) Excludes unamortized discounts and premiums, fair value accounting adjustments and finance leases.
(2) Interest on variable-rate debt based on rates as of December 31, 2019.
(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, 2019.
(6) Assumes FES Debtors emergence in 2020, see Note 1, "Organization and Basis of Presentation," of the Notes to Consolidated Financial Statements for further discussion on settlement.
(7) Estimated amounts owed to the FES Debtors under the intercompany tax allocation agreement for the 2018 and 2019 tax returns, see Note 1, "Organization and Basis of Presentation," of the Notes to Consolidated Financial Statements for further discussion on tax sharing agreement with the FES Debtors.

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 2020.

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

NUCLEAR INSURANCE

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, 2019, was approximately $1.6 billion, as summarized below:

Guarantees and Other Assurances	**Maximum Exposure**
	(In millions)
FE's Guarantees on Behalf of the FES Debtors	
Surety Bonds - FG[(1)]	$ 200
Deferred compensation arrangements	150
	350
FE's Guarantees on Behalf of its Consolidated Subsidiaries	
AE Supply asset sales[(2)]	555
Deferred compensation arrangements	466
Fuel related contracts and other	10
	1,031
FE's Guarantees on Other Assurances	
Global Holding Facility	114
Surety Bonds	135
LOCs and other	16
	265
Total Guarantees and Other Assurances	$ 1,646

(1) 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.

(2) 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 provided 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.

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, 2019, AE Supply has posted no collateral. The Utilities and Transmission Companies have posted no collateral.

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, 2019:

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	—	36	—	36
Surety Bonds (Collateralized Amount)[(1)]	—	63	257	320
Total Exposure from Contractual Obligations	$ 1	$ 99	$ 257	$ 357

[(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 $120 million syndicated senior secured term loan facility due November 12, 2024, under which Global Holding's outstanding principal balance is $114 million as of December 31, 2019. 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, 2019, FirstEnergy has a net liability of $13 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, 2019, the FirstEnergy pension plan assets were allocated approximately as follows: 29% in equity securities, 36% in fixed income securities, 9% in hedge funds, 2% in insurance-linked securities, 7% in real estate, 4% in private equity and 13% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. 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, 2019, FirstEnergy's pension plan assets have earned approximately 20.3% as compared to an annual expected return on plan assets of 7.50%.

As of December 31, 2019, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through December 31, 2019, FirstEnergy's OPEB plans have earned approximately 18.1% as compared to an annual expected return on plan assets of 7.50%.

NDT funds have been established to satisfy JCP&L, ME and PN's nuclear decommissioning obligations associated with TMI-2. As of December 31, 2019, approximately 15% and 85% of the funds were invested in fixed income securities and short-term investments, respectively, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $135 million and $763 million for fixed income securities and short-term investments, respectively, as of December 31, 2019, excluding $16 million of net receivables, payables and accrued income. 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 2019, 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	2020	2021	2022	2023	2024	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ —	$ —	$ —	$ —	$ —	$ 401	$ 401	$ 401
Average interest rate	—%	—%	—%	—%	—%	3.0%	3.0%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 364	$ 132	$ 1,142	$ 1,194	$ 1,246	$ 15,238	$ 19,316	$ 22,178
Average interest rate	5.4%	3.7%	4.1%	4.1%	4.7%	4.9%	4.8%	
Variable rate	$ —	$ 750	$ —	$ —	$ —	$ —	$ 750	$ 750
Average interest rate	—%	2.5%	—%	—%	—%	—%	2.5%	

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. A primary factor contributing to these actuarial gains and losses are changes in the discount rates used to value pension and OPEB obligations as of the measurement date and the difference between expected and actual returns on the plans’ assets. Upon the FES Debtors' emergence from bankruptcy, FirstEnergy will perform a remeasurement of the pension and OPEB plans. Assuming an emergence in the first quarter of 2020, FirstEnergy anticipates an after-tax mark-to-market loss to be up to $400 million assuming a discount rate of approximately 3.10% to 3.35% and a return on the pension and OPEB plans’ assets based on actual investment performance through January 31, 2020.

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 affected company 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 New Jersey by the NJBPU, in Ohio by the PUCO, 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)	March 2019	47% / 53%	9.65%
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 March 23, 2019. 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 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.

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. The MDPSC approved PE’s compliance filing, which implements the pilot program, with minor modifications, on July 3, 2019.

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 reflected $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On March 22, 2019, the MDPSC issued a final order that approved a rate increase of $6.2 million, approved three of the four EDIS programs for four years, directed PE to file a new depreciation study within 18 months, and ordered the filing of a new base rate case in four years to correspond to the ending of the approved EDIS programs.

NEW JERSEY

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

On April 18, 2019, pursuant to the May 2018 New Jersey enacted legislation establishing a ZEC program to provide ratepayer funded subsidies of New Jersey nuclear energy supply, the NJBPU approved the implementation of a non-bypassable, irrevocable ZEC charge for all New Jersey electric utility customers, including JCP&L’s customers. Once collected from customers by JCP&L, these funds will be remitted to eligible nuclear energy generators.

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 ratepayers; 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. On May 17, 2019, the Rate Counsel filed an appeal with the Appellate Division of the Superior Court of New Jersey. JCP&L is contesting this appeal but is unable to predict the outcome of this matter.

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 April 23, 2019, JCP&L filed a Stipulation of Settlement with the NJBPU on behalf of the JCP&L, Rate Counsel, NJBPU Staff and New Jersey Large Energy Users Coalition, which provides that JCP&L will invest up to approximately $97 million in capital investments beginning on June 1, 2019 through December 31, 2020. JCP&L shall seek recovery of the capital investment through an accelerated cost recovery mechanism, provided for in the rules, that includes a revenue adjustment calculation and a process for two rate adjustments. On May 8, 2019, the NJBPU issued an order approving the Stipulation of Settlement without modifications. Pursuant to the Stipulation, JCP&L filed a petition on September 16, 2019, to seek approval of rate adjustments to provide for cost recovery established with JCP&L Reliability Plus.

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. On April 23, 2019, JCP&L filed a Stipulation of Settlement on behalf of the Rate Counsel, NJBPU Staff, and the New Jersey Large Energy Users Coalition with the NJBPU. The terms of the Stipulation of Settlement provide that between January 1, 2018 and March 31, 2018, JCP&L's refund obligation is estimated to be approximately $7 million, which was refunded to customers in 2019. The Stipulation of Settlement also provides for a base rate reduction of $28.6 million, which was reflected in rates on April 1, 2018, and a Rider Tax Act Adjustment for certain items over a five-year period. On May 8, 2019, the NJBPU issued an order approving the Stipulation of Settlement without modification.

JCP&L expects to file a distribution base rate case in New Jersey in February 2020, which will seek to recover certain costs associated with providing safe and reliable electric service to JCP&L customers, along with recovery of previously incurred storm costs.

OHIO

The Ohio Companies operate under base distribution rates approved by the PUCO effective in 2009. The Ohio Companies' residential and commercial base distribution revenues are decoupled, through a mechanism that took effect on February 1, 2020, to the base distribution revenue and lost distribution revenue associated with energy efficiency and peak demand reduction programs recovered as of the twelve-month period ending on December 31, 2018. The Ohio Companies currently operate under ESP IV effective June 1, 2016, and continuing through May 31, 2024, that continues the supply of power to non-shopping customers at a market-based price set through an auction process. ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $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. In addition, ESP IV includes: (1) continuation of a base distribution rate freeze through May 31, 2024; (2) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; and (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.

ESP IV further provided for the Ohio Companies to collect through Rider DMR $132.5 million annually for three years beginning in 2017, grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. Revenues from Rider DMR are excluded from the significantly excessive earnings test. On appeal, the SCOH, on June 19, 2019, reversed the PUCO's determination that Rider DMR is lawful, and remanded the matter to the PUCO with instructions to remove Rider DMR from ESP IV. On August 20, 2019, the SCOH denied the Ohio Companies' motion for reconsideration. The PUCO entered an Order directing the Ohio Companies to cease further collection through Rider DMR, credit back to customers a refund of Rider DMR funds collected since July 2, 2019, and remove Rider DMR from ESP IV. On October 1, 2019, the Ohio

Companies implemented PUCO approved tariffs to refund approximately $28 million to customers, including Rider DMR revenues billed from July 2, 2019 through August 31, 2019.

On July 15, 2019, OCC filed a Notice of Appeal with the SCOH, challenging the PUCO's exclusion of Rider DMR revenues from the determination of the existence of significantly excessive earnings under ESP IV for calendar year 2017 and claiming a $42 million refund is due to OE customers. The Ohio Companies are contesting this appeal but are unable to predict the outcome of this matter.

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 includes a portfolio of energy efficiency programs targeted to a variety of customer segments. The Ohio Companies anticipate the cost of the plan will be approximately $268 million over the life of the plan 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 plan 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 October 15, 2019, the SCOH reversed the PUCO's decision to impose the 4% cost-recovery cap and remanded the matter to the PUCO for approval of the portfolio plans without the cost-recovery cap.

On July 23, 2019, Ohio enacted legislation establishing support for nuclear energy supply in Ohio. In addition to the provisions supporting nuclear energy, the legislation included a provision implementing a decoupling mechanism for Ohio electric utilities. The legislation also is ending current energy efficiency program mandates on December 31, 2020, provided statewide energy efficiency mandates are achieved as determined by the PUCO. On October 23, 2019, the PUCO solicited comments on whether the PUCO should terminate the energy efficiency programs once the statewide energy efficiency mandates are achieved. Opponents to the legislation sought to submit it to a statewide referendum, and stay its effect unless and until approved by a majority of Ohio voters. Petitioners filed a lawsuit in the U.S. District Court for the Southern District of Ohio seeking additional time to gather signatures in support of a referendum. Petitioners failed to file the necessary number of petition signatures, and the legislation took effect on October 22, 2019. On October 23, 2019, the U.S. District Court denied petitioners' request for more time, and certified questions of state law to the SCOH to answer. Petitioners appealed the U.S. District Court's decision to the U.S. Court of Appeals for the Sixth Circuit. The Petitioners ended their challenge to the legislation voluntarily at the end of January 2020 causing the dismissal of the appeal, the lawsuit before the U.S District Court, and the proceedings before the SCOH.

On November 21, 2019, the Ohio Companies applied to the PUCO for approval of a decoupling mechanism, which would set residential and commercial base distribution related revenues at the levels collected in 2018. As such, those base distribution revenues would no longer be based on electric consumption, which allows continued support of energy efficiency initiatives while also providing revenue certainty to the Ohio Companies. On January 15, 2020, the PUCO approved the Ohio Companies' decoupling application, and the decoupling mechanism took effect on February 1, 2020.

In February 2016, the Ohio Companies filed a Grid Modernization Business Plan for PUCO consideration and approval, as required by the terms of ESP IV. On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan, a portfolio 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. Also, on January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act on Ohio utilities' rates and determine the appropriate course of action to pass benefits on to customers. 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 to flow back to customers. 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 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 had 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. On July 17, 2019, the PUCO approved the settlement agreement with no material modifications. On September 11, 2019, the PUCO denied the application for rehearing of environmental advocates who were not parties to the settlement.

The Ohio Companies' Rider NMB is designed to recover NMB transmission-related costs imposed on or charged to the Ohio Companies by FERC or PJM. On December 14, 2018, the Ohio Companies filed an application for a review of their 2019 Rider NMB, including recovery of future Legacy RTEP costs and previously absorbed Legacy RTEP costs, net of refunds received from PJM. On February 27, 2018, the PUCO issued an order directing the Ohio Companies to file revised final tariffs recovering Legacy RTEP costs incurred since May 31, 2018, but excluding recovery of approximately $95 million in Legacy RTEP costs incurred prior to May 31, 2018, net of refunds received from PJM. The PUCO solicited comments on whether the Ohio Companies should be permitted to recover the Legacy RTEP charges incurred prior to May 31, 2018. On October 9, 2019, the PUCO approved the recovery of the $95 million of previously excluded Legacy RTEP charges.

PENNSYLVANIA

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. These rates were adjusted for the net impact of the Tax Act, effective March 15, 2018. The net impact of the Tax Act for the period January 1, 2018 through March 14, 2018 must also be separately tracked for treatment in a future rate proceeding. The Pennsylvania Companies operate under DSPs for the June 1, 2019 through May 31, 2023 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 2019-2023 DSPs, 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, modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW, customer assistance program shopping limitations, and script modifications related to the Pennsylvania Companies' customer referral programs.

Pursuant to Pennsylvania 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. 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. Following a periodic review of the LTIIPs in 2018 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 May 23, 2019, the PPUC approved the Pennsylvania Companies' Modified LTIIPs that revised LTIIP spending in 2019 of approximately $45 million by ME, $25 million by PN, $26 million by Penn and $51 million by WP, and terminating at the end of 2019. On August 30, 2019, the Pennsylvania Companies filed Petitions for approval of proposed LTIIPs for the five-year period beginning January 1, 2020 and ending December 31, 2024 for a total capital investment of approximately $572 million for certain infrastructure improvement initiatives. On January 16, 2020, the PPUC approved the LTIIPs without modification, as well as directed the Pennsylvania Companies to submit corrective action plans by March 16, 2020, which outline how they will reduce their pole replacement backlogs over a five-year period to a rolling two-year backlog.

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. The parties to the DSIC proceeding submitted a Joint Settlement that resolved the issues that were pending from the order issued on June 9, 2016, and 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. The Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision, and the Pennsylvania Companies contested the appeal. The Commonwealth Court reversed the PPUC's decision of April 19, 2018 and remanded the matter to the PPUC to require the Pennsylvania Companies to revise their tariffs and DSIC calculations to include ADIT and state income taxes. The Commonwealth Court denied Applications for Reargument in the Court's July 11, 2019 Opinion and Order filed by the PPUC and the Pennsylvania Companies. On October 7, 2019, the PPUC and the Pennsylvania Companies filed separate Petitions for Allowance of Appeal of the Commonwealth Court's Opinion and Order to the Pennsylvania Supreme Court.

On August 30, 2019, Penn filed a Petition seeking approval of a waiver of the statutory DSIC cap of 5% of distribution rate revenue and approval to increase the maximum allowable DSIC to 11.81% of distribution rate revenue for the five-year period of its proposed LTIIP. The Pennsylvania Office of Small Business Advocate, the PPUC's Bureau of Investigation, and the Pennsylvania OCA opposed Penn's Petition. On January 17, 2020, the parties filed a petition seeking approval of settlement that provides for a temporary increase in the recoverability cap from 5% to 7.5%, which will expire on the earlier of the effective date of new base rates following Penn's next base rate case or the expiration of its LTIIP II program. The settlement is subject to PPUC approval.

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.

On August 21, 2019, MP and PE filed with the WVPSC their annual ENEC case requesting a decrease in ENEC rates of $6.1 million beginning January 1, 2020, representing a 0.4% decrease in rates versus those in effect on August 21, 2019. On October 11, 2019, MP and PE filed a supplement requesting approval of the termination of the 50 MW PPA with Morgantown Energy Associates, a NUG entity. A settlement between MP, PE, and the majority of the intervenors fully resolving the ENEC case, which maintains 2019 ENEC rates into 2020, and supports the termination of the Morgantown Energy Associates PPA, was filed with the WVPSC on October 18, 2019. An order was issued on December 20, 2019, approving the ENEC settlement and termination of the PPA with Morgantown Energy Associates.

On August 21, 2019, MP and PE filed with the WVPSC for a reconciliation of their VMS and a periodic review of its vegetation management program requesting an increase in VMS rates of $7.6 million beginning January 1, 2020. The increase is due to moving from a 5-year maintenance cycle to a 4-year cycle and performing more operation and maintenance work and less capital work on the rights of way. The increase is a 0.5% increase in rates versus those in effect on August 21, 2019. All the parties reached a settlement in the case, and the WVPSC issued its order approving the settlement without change on December 20, 2019.

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 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[1]	Settled[1][3]	Settled[1][3]
MP	March 21, 2018[2]	Settled[3]	Settled[3]
PE	March 21, 2018[2]	Settled[3]	Settled[3]
WP	March 21, 2018[2]	Settled[3]	Settled[3]
MAIT	July 1, 2017	Lower of Actual (13 month average) or 60%	10.3%
TrAIL	July 1, 2008	Actual (year-end)	12.7% (TrAIL the Line & Black Oak SVC) 11.7% (All other projects)

(1) Effective on January 1, 2020, JCP&L has implemented a forward-looking formula rate, which has been accepted by FERC, subject to refund, pending further hearing and settlement proceedings.
(2) See FERC Actions on Tax Act below.
(3) FERC-approved settlement agreements did not specify.

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 six 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 material 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.

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.

FERC Actions on Tax Act

On March 15, 2018, FERC initiated proceedings on the question of how to 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 21, 2019, FERC issued a final rule (Order 864). Order 864 requires utilities with transmission formula rates to update their formula rate templates to include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate base; (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. Alternatively, formula rate utilities can demonstrate to FERC that their formula rate template already achieves these outcomes. Utilities with transmission stated rates are required to address these new requirements as part of their next transmission rate case. 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. FirstEnergy’s formula rate transmission utilities will make the required filings on or before the deadlines established in FERC’s order. FirstEnergy’s stated rate transmission utilities will address the requirements as part of their next transmission rate case. JCP&L is addressing the requirements in the course of its pending transmission rate case.

Transmission ROE Methodology

FERC’s methodology for calculating electric transmission utility ROE has been in transition as a result of an April 14, 2017 ruling by the D.C. Circuit that vacated FERC’s then-effective methodology. On October 16, 2018, FERC issued an order in which it proposed a revised ROE methodology. FERC proposed that, for complaint proceedings alleging that an existing ROE is not just and reasonable, FERC will rely on three financial models - discounted cash flow, capital-asset pricing, and expected earnings - to establish a composite zone of reasonableness to identify 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 replacement 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. On March 21, 2019, FERC established NOIs to collect industry and stakeholder comments on the revised ROE methodology that is described in the October 16, 2018 decision, and also whether to make changes to FERC’s existing policies and practices for awarding transmission rates incentives. On November 21, 2019, FERC announced in a complaint proceeding involving MISO utilities that FERC would rely on the discounted cash flow and capital-asset pricing models as the basis for establishing ROE. It is not clear at this time whether FERC’s November ruling will be applied more broadly. Any changes to FERC’s transmission rate ROE and incentive policies would be applied on a prospective basis. FirstEnergy currently is participating through various trade groups in the FERC dockets where the ROE methodology is being reviewed, and on December 23, 2019, JCP&L filed a request for rehearing of FERC’s November decision in the MISO utilities docket.

JCP&L Transmission Formula Rate

On October 30, 2019, JCP&L filed tariff amendments with FERC to convert JCP&L’s existing stated transmission rate to a forward-looking formula transmission rate. JCP&L requested that the tariff amendments become effective January 1, 2020. On December 19, 2019, FERC issued its initial order in the case, allowing JCP&L to transition to a forward-looking formula rate as of January 1, 2020 as requested, subject to refund, pending further hearing and settlement proceedings. JCP&L is engaged in settlement negotiations.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. While FirstEnergy's environmental policies and procedures are designed to achieve compliance with applicable environmental laws and regulations, such laws and regulations are subject to periodic review and potential revision by the implementing agencies. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof may materially impact its business, results of operations, cash flows and financial condition.

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. On September 13, 2019, the D.C. Circuit remanded the CSAPR update rule to the EPA citing that the rule did not eliminate upwind states' significant contributions to downwind states' air quality attainment requirements within applicable attainment deadlines. 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 materially impact FirstEnergy's operations, cash flows and financial condition.

In February 2019, the EPA announced its final decision to retain without changes the NAAQS for SO_2, specifically retaining the 2010 primary (health-based) 1-hour standard of 75 PPB. As of September 30, 2019, FirstEnergy has no power plants operating in areas designated as non-attainment by the EPA.

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's 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. On September 20, 2019, the EPA denied New York's CAA Section 126 petition. On October 29, 2019, the State of New York appealed the denial of its petition to the D.C. Circuit. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

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. In 2015, FirstEnergy set a goal of reducing company-wide CO2 emissions by at least 90 percent below 2005 levels by 2045. As of December 31, 2018, FirstEnergy has reduced its CO2 emissions by approximately 62 percent. In September 2016, the U.S. 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's non-binding obligations to limit global warming to 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 CO2 emissions, or litigation alleging damages from GHG emissions, could require material capital and other expenditures or result in changes to its operations.

In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for GHG under the Clean Air Act," 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 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 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. On June 19, 2019, the EPA repealed the CPP and replaced it with the ACE rule that establishes guidelines for states to develop standards of performance to address GHG emissions from existing coal-fired power plants. Depending on the outcomes of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be material.

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 facilities. 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 on September 18, 2017, the EPA postponed certain compliance deadlines for two years. On November 4, 2019, the EPA issued a proposed rule revising the effluent limits for discharges from wet scrubber systems and extending the deadline for compliance to December 31, 2025. The EPA's proposed rule retains the zero discharge standard and 2023 compliance date for ash transport water, but adds some allowances for discharge under certain circumstances. In addition, the EPA allows for less stringent limits for sub-categories of generating units based on capacity utilization, flow volume from the scrubber system, and unit retirement date. 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.

On September 29, 2016, FirstEnergy received a request from the EPA for information pursuant to CWA Section 308(a) for information concerning boron exceedances of effluent limitations established in the NPDES Permit for the former Mitchell Power Station's Mingo landfill, owned by WP. On November 1, 2016, WP provided an initial response that contained information related to a similar boron issue at the former Springdale Power Station's landfill. The EPA requested additional information regarding the Springdale landfill and on November 15, 2016, WP provided a response and intends to fully comply with the Section 308(a) information request. On March 3, 2017, WP proposed to the PA DEP a re-route of its wastewater discharge to eliminate potential boron exceedances at the Springdale landfill. On January 29, 2018, WP submitted an NPDES permit renewal application to PA DEP proposing to re-route its wastewater discharge to eliminate potential boron exceedances at the Mingo landfill. On February 20, 2018, the DOJ issued a letter and tolling agreement on behalf of EPA alleging violations of the CWA at the Mingo landfill while seeking to enter settlement negotiations in lieu of filing a complaint. On November 4, 2019, the EPA proposed a penalty of nearly $1.3 million to settle alleged past boron exceedances at the Mingo and Springdale landfills. On December 17, 2019, WP responded to the EPA's settlement proposal but is unable to predict the outcome of this matter.

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. On November 4, 2019, the EPA issued a proposed rule accelerating the date that certain CCR impoundments must cease accepting waste and initiate closure to August 31, 2020. The proposed rule, which includes a 60-day comment period, provides exceptions, which could allow extensions to closure dates.

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, 2019, 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 $109 million have been accrued through December 31, 2019. Included in the total are accrued liabilities of approximately $77 million for environmental remediation of former MGP 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, 2019, JCP&L, ME and PN had in total approximately $882 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.

On October 15, 2019, JCP&L, ME, PN and GPUN executed an asset purchase and sale agreement with TMI-2 Solutions, LLC, a subsidiary of Energy*Solutions*, LLC, concerning the transfer and dismantlement of TMI-2. This transfer of TMI-2 to TMI-2 Solutions, LLC will include the transfer of: (i) the ownership and operating NRC licenses for TMI-2; (ii) the external trusts for the decommissioning and environmental remediation of TMI-2; and (iii) related liabilities of approximately $900 million as of December 31, 2019. There can be no assurance that the transfer will receive the required regulatory approvals and, even if approved, whether the conditions to the closing of the transfer will be satisfied. On November 12, 2019, JCP&L filed a Petition with the NJBPU seeking approval of the transfer and sale of JCP&L’s entire 25% interest in TMI-2 to TMI-2 Solutions, LLC. Also on November 12, 2019, JCP&L, ME, PN, GPUN and TMI-2 Solutions, LLC filed an application with the NRC seeking approval to transfer the NRC license for TMI-2 to TMI-2 Solutions, LLC. Both proceedings are ongoing.

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 14, "Regulatory Matters."

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 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. Management applies judgment in evaluating the evidence available to assess the probability of recovery of regulatory assets from customers, including, but not limited to evaluating evidence related to precedent for similar items experienced at the Company and comparable companies within similar jurisdictions, as well as assessing progress of communications between the Company and regulators. 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 14, "Regulatory Matters," for additional information.

FirstEnergy reviews the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Similarly, FirstEnergy records regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. If recovery of a regulatory asset is no longer probable, FirstEnergy will write off that regulatory asset as a charge against earnings. 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, 2019, 2018, and 2017, were $676 million, $145 million, and $141 million, respectively, of these amounts, approximately $2 million, $1 million, and $39 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 3.34%, 4.44% and 3.75% as of December 31, 2019, 2018 and 2017, respectively. The assumed discount rates for OPEB were 3.18%, 4.30% and 3.50% as of December 31, 2019, 2018 and 2017, 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 election is considered a change in estimate and, accordingly, accounted for prospectively, and did not have a material impact on FirstEnergy's financial statements.

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 2019, FirstEnergy’s qualified pension and OPEB plan assets experienced gains of $1,492 million or 20.2%, compared to losses of $371 million, or (4)% in 2018, and gains of $999 million, or 15.1% in 2017 and assumed a 7.50% rate of return on plan assets in 2019, 2018 and 2017, which generated $569 million, $605 million and $478 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 decrease or increase 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 2020 is 7.50%.

During 2019, the Society of Actuaries published new mortality tables that include more current data than the RP-2014 tables as well as new improvement scales. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the Pri-2012 mortality table with projection scale MP-2019 was most appropriate. As such, the Pri-2012 mortality table with projection scale MP-2019 was utilized to determine the 2019 benefit cost and obligation as of December 31, 2019 for the FirstEnergy pension and OPEB plans. The impact of using the Pri-2012 mortality table with projection scale MP-2019 resulted in a decrease to the projected benefit obligation approximately $29 million and $3 million for the pension and OPEB plans, respectively, and was included in the 2019 pension and OPEB mark-to-market adjustment.

Based on discount rates of 3.34% for pension, 3.18% for OPEB and an estimated return on assets of 7.50%, FirstEnergy expects its 2020 pre-tax net periodic benefit credit to be approximately $108 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2020 or impacts resulting from FES' emergence from bankruptcy). Upon the FES Debtors' emergence from bankruptcy, FirstEnergy will perform a remeasurement of the pension and OPEB plans. Assuming an emergence in the first quarter of 2020, FirstEnergy anticipates an after-tax mark-to-market loss to be up to $400 million assuming a discount rate of approximately 3.10% to 3.35% and a return on the pension and OPEB plans’ assets based on actual investment performance through January 31, 2020.

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, 2019, 2018, and 2017:

Postemployment Benefits Expense (Credits)	**2019**	**2018**	**2017**
		(In millions)	
Pension	$ 622	$ 200	$ 247
OPEB	(21)	(158)	(45)
Total	$ 601	$ 42	$ 202

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 2019 and 2018, 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 2020 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%	$ 360	$ 16	$ 376
Long-term return on assets	Decrease by 0.25%	$ 20	$ 1	$ 21
Health care trend rate	Increase by 1.0%	N/A	$ 20	$ 20

See Note 5, "Pension and Other Postemployment Benefits," for additional information.

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 FirstEnergy income taxes.

NEW ACCOUNTING PRONOUNCEMENTS

ASU 2016-02, *"Leases (Topic 842)"* (Issued February 2016 and subsequently updated to address implementation questions): The new guidance requires 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 implemented a third-party software tool that assisted with the initial adoption and will assist with ongoing compliance. FirstEnergy chose to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Upon adoption, on January 1, 2019, FirstEnergy increased assets and liabilities by $186 million, with no impact to results of operations or cash flows. See Note 8, "Leases," for additional information on FirstEnergy's leases.

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB has not yet been adopted. 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 based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting.

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 expected credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost 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, with early adoption permitted. FirstEnergy has analyzed its financial instruments within the scope of this guidance, primarily trade receivables, AFS debt securities and certain third-party guarantees and does not expect a material impact to its financial statements upon adoption in 2020.

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. FirstEnergy does not expect a material impact to its financial statements upon adoption in 2020.

ASU 2019-12, "*Simplifying the Accounting for Income Taxes"* (Issued in December 2019): ASU 2019-12 enhances and simplifies various aspects of the income tax accounting guidance including the elimination of certain exceptions related to the approach for intraperiod tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. The new guidance also simplifies aspects of the accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. The guidance will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020, 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

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework* published in 2013, management conducted an evaluation of the effectiveness of their internal control over financial reporting under the supervision of the chief executive officer and chief financial officer. Based on that evaluation, management concluded that FirstEnergy's internal control over financial reporting was effective as of December 31, 2019. The effectiveness of FirstEnergy's internal control over financial reporting, as of December 31, 2019, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report included herein.

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, 2019 and 2018, 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, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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, 2019, 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 the accompanying Management's Report on Internal Control over Financial Reporting. 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Recoverability of Regulatory Assets That Do Not Have an Order for Recovery

As described in Note 1 to the consolidated financial statements, the Company accounts for the effects of regulation through the application of regulatory accounting to its regulated distribution and transmission subsidiaries as 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. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. Management assesses the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. Management applies judgment in evaluating the evidence available to assess the probability of recovery of regulatory assets from customers and certain of these assets, totaling approximately $111 million as of December 31, 2019, have been recorded based on precedent and rate making premises without a specific order.

The principal considerations for our determination that performing procedures relating to the Company’s recoverability of regulatory assets that do not have an order for recovery is a critical audit matter are there was significant judgment by management when assessing the probability of recovery of these regulatory assets from customers. This led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the recoverability of these regulatory assets.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the Company’s regulatory accounting process, including controls over management’s assessment of the recoverability of regulatory assets that do not have an order for recovery. These procedures also included evaluating the reasonableness of management’s assessment of recoverability of regulatory assets which involved evaluating evidence related to precedent for similar items at the Company and information on comparable companies within similar regulatory jurisdictions as well as assessing progress of communications between management and regulators.

/s/ PricewaterhouseCoopers LLP
Cleveland, Ohio
February 10, 2020

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, 2019	2018	2017
REVENUES:			
Distribution services and retail generation	$ 8,720	$ 8,937	$ 8,685
Transmission	1,510	1,335	1,307
Other	805	989	936
Total revenues[1]	11,035	11,261	10,928
OPERATING EXPENSES:			
Fuel	497	538	497
Purchased power	2,927	3,109	2,926
Other operating expenses	2,952	3,133	2,802
Provision for depreciation	1,220	1,136	1,027
Amortization (deferral) of regulatory assets, net	(79)	(150)	308
General taxes	1,008	993	940
Total operating expenses	8,525	8,759	8,500
OPERATING INCOME	2,510	2,502	2,428
OTHER INCOME (EXPENSE):			
Miscellaneous income, net	243	205	53
Pension and OPEB mark-to-market adjustment	(674)	(144)	(102)
Interest expense	(1,033)	(1,116)	(1,005)
Capitalized financing costs	71	65	52
Total other expense	(1,393)	(990)	(1,002)
INCOME BEFORE INCOME TAXES	1,117	1,512	1,426
INCOME TAXES	213	490	1,715
INCOME (LOSS) FROM CONTINUING OPERATIONS	904	1,022	(289)
Discontinued operations (Note 3)[2]	8	326	(1,435)
NET INCOME (LOSS)	$ 912	$ 1,348	$ (1,724)
INCOME ALLOCATED TO PREFERRED STOCKHOLDERS (Note 1)	4	367	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ 908	$ 981	$ (1,724)
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ 1.69	$ 1.33	$ (0.65)
Basic - Discontinued Operations	0.01	0.66	(3.23)
Basic - Net Income (Loss) Attributable to Common Stockholders	$ 1.70	$ 1.99	$ (3.88)
Diluted - Continuing Operations	$ 1.67	$ 1.33	$ (0.65)
Diluted - Discontinued Operations	0.01	0.66	(3.23)
Diluted - Net Income (Loss) Attributable to Common Stockholders	$ 1.68	$ 1.99	$ (3.88)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	535	492	444
Diluted	542	494	444

(1) Includes excise and gross receipts tax collections of $373 million, $386 million and $370 million in 2019, 2018 and 2017, respectively.

(2) Net of income tax benefit of $5 million, $1,251 million, and $820 million in 2019, 2018 and 2017, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)	For the Years Ended December 31, 2019	2018	2017
NET INCOME (LOSS)	$ 912	$ 1,348	$ (1,724)
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(31)	(83)	(85)
Amortized losses on derivative hedges	2	21	10
Change in unrealized gains on available-for-sale securities	—	(106)	22
Other comprehensive loss	(29)	(168)	(53)
Income tax benefits on other comprehensive loss	(8)	(67)	(21)
Other comprehensive loss, net of tax	(21)	(101)	(32)
COMPREHENSIVE INCOME (LOSS)	$ 891	$ 1,247	$ (1,756)

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2019	December 31, 2018
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 627	$ 367
Restricted cash	52	62
Receivables-		
Customers, net of allowance for uncollectible accounts of $46 in 2019 and $50 in 2018	1,091	1,221
Affiliated companies, net of allowance for uncollectible accounts of $1,063 in 2019 and $920 in 2018	—	20
Other, net of allowance for uncollectible accounts of $21 in 2019 and $2 in 2018	203	270
Materials and supplies, at average cost	281	252
Prepaid taxes and other	157	175
Current assets - discontinued operations	33	25
	2,444	2,392
PROPERTY, PLANT AND EQUIPMENT:		
In service	41,767	39,469
Less — Accumulated provision for depreciation	11,427	10,793
	30,340	28,676
Construction work in progress	1,310	1,235
	31,650	29,911
INVESTMENTS:		
Nuclear plant decommissioning trusts	—	790
Nuclear fuel disposal trust	270	256
Other	299	253
Investments - held for sale (Note 15)	882	—
	1,451	1,299
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	5,618
Regulatory assets	99	91
Other	1,039	752
	6,756	6,461
	$ 42,301	$ 40,063
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 380	$ 503
Short-term borrowings	1,000	1,250
Accounts payable	918	965
Accounts payable - affiliated companies	87	—
Accrued interest	249	243
Accrued taxes	545	533
Accrued compensation and benefits	258	318
Other	1,425	822
	4,862	4,634
CAPITALIZATION:		
Stockholders' equity-		
Common stock, $0.10 par value, authorized 700,000,000 shares - 540,652,222 and 511,915,450 shares outstanding as of December 31, 2019 and December 31, 2018, respectively	54	51
Preferred stock, $100 par value, authorized 5,000,000 shares, of which 1,616,000 are designated Series A Convertible Preferred - none outstanding as of December 31, 2019, and 704,589 shares outstanding as of December 31, 2018	—	71

Other paid-in capital	10,868	11,530
Accumulated other comprehensive income	20	41
Accumulated deficit	(3,967)	(4,879)
Total stockholders' equity	6,975	6,814
Long-term debt and other long-term obligations	19,618	17,751
	26,593	24,565
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,849	2,502
Retirement benefits	3,065	2,906
Regulatory liabilities	2,360	2,498
Asset retirement obligations	165	812
Adverse power contract liability	49	89
Other	1,667	2,057
Noncurrent liabilities - held for sale (Note 15)	691	—
	10,846	10,864
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$ 42,301	$ 40,063

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In millions)	Series A Convertible Preferred Stock Shares	Series A Convertible Preferred Stock Amount	Common Stock Shares	Common Stock Amount	OPIC	AOCI	Accumulated Deficit	Total Stockholders' Equity
Balance, January 1, 2017	—	$ —	442	$ 44	$ 10,555	$ 174	$ (4,532)	$ 6,241
Net loss							(1,724)	(1,724)
Other comprehensive loss, net of tax						(32)		(32)
Stock-based compensation					36			36
Cash dividends declared on common stock					(639)			(639)
Stock Investment Plan and certain share-based benefit plans			3		56			56
Reclass to liability awards					(7)			(7)
Share-based compensation accounting change							(6)	(6)
Balance, December 31, 2017	—	—	445	44	10,001	142	(6,262)	3,925
Net income							1,348	1,348
Other comprehensive loss, net of tax						(101)		(101)
Stock-based compensation					60			60
Cash dividends declared on common stock					(906)			(906)
Cash dividends declared on preferred stock					(71)			(71)
Stock Investment Plan and certain share-based benefit plans			4	1	61			62
Stock issuance (Note 11)[1]	1.6	162	30	3	2,297			2,462
Conversion of Series A Convertible Stock (Note 11)	(0.9)	(91)	33	3	88			—
Impact of adopting new accounting pronouncements							35	35
Balance, December 31, 2018	0.7	71	512	51	11,530	41	(4,879)	6,814
Net income							912	912
Other comprehensive loss, net of tax						(21)		(21)
Stock-based compensation					41			41
Cash dividends declared on common stock					(824)			(824)
Cash dividends declared on preferred stock					(3)			(3)
Stock Investment Plan and certain share-based benefit plans			3		56			56
Conversion of Series A Convertible Stock (Note 11)	(0.7)	(71)	26	3	68			—
Balance, December 31, 2019	—	$ —	541	$ 54	$ 10,868	$ 20	$ (3,967)	$ 6,975

[1] The Preferred Stock included an embedded conversion option at a price that is below the fair value of the Common Stock on the commitment date. This beneficial conversion feature (BCF), which was approximately $296 million, was recorded to OPIC as well as the amortization of the BCF (deemed dividend) through the period from the issue date to the first allowable conversion date (July 22, 2018) and as such there is no net impact to OPIC for the year ended December 31, 2018. See Note 1, "Organization and Basis of Presentation - Earnings per share," and Note 11, "Capitalization" for additional information on the BCF and the equity issuance.

Dividends declared for each share of common stock and as-converted share of preferred stock was $1.53 during 2019, $1.82 during 2018, and $1.44 during 2017.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2019	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 912	$ 1,348	$ (1,724)
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Gain on disposal, net of tax (Note 3)	(59)	(435)	—
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	1,217	1,384	1,700
Impairment of assets and related charges	—	—	2,399
Pension trust contributions	(500)	(1,250)	—
Retirement benefits, net of payments	(108)	(137)	29
Pension and OPEB mark-to-market adjustment	676	144	141
Deferred income taxes and investment tax credits, net	252	485	839
Asset removal costs charged to income	28	42	22
Unrealized (gain) loss on derivative transactions	—	(5)	81
Gain on sale of investment securities held in trusts	—	(9)	(63)
Changes in current assets and liabilities-			
Receivables	271	(248)	(39)
Materials and supplies	(37)	24	(6)
Prepaid taxes and other	10	(61)	30
Accounts payable	(49)	109	72
Accrued taxes	12	—	(9)
Accrued interest	6	(25)	55
Accrued compensation and benefits	(60)	37	(27)
Other current liabilities	(21)	(121)	(35)
Other	(83)	128	343
Net cash provided from operating activities	2,467	1,410	3,808
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	2,300	1,474	4,675
Short-term borrowings, net	—	950	—
Preferred stock issuance	—	1,616	—
Common stock issuance	—	850	—
Redemptions and repayments-			
Long-term debt	(789)	(2,608)	(2,291)
Short-term borrowings, net	—	—	(2,375)
Tender premiums paid on debt redemptions	—	(89)	—
Preferred stock dividend payments	(6)	(61)	—
Common stock dividend payments	(814)	(711)	(639)
Other	(35)	(27)	(72)
Net cash provided from (used for) financing activities	656	1,394	(702)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,665)	(2,675)	(2,587)
Nuclear fuel	—	—	(254)
Proceeds from asset sales	47	425	388
Sales of investment securities held in trusts	1,637	909	2,170
Purchases of investment securities held in trusts	(1,675)	(963)	(2,268)
Notes receivable from affiliated companies	—	(500)	—
Asset removal costs	(217)	(218)	(172)

Other	—	4	—
Net cash used for investing activities	(2,873)	(3,018)	(2,723)
Net change in cash, cash equivalents and restricted cash	250	(214)	383
Cash, cash equivalents, and restricted cash at beginning of period	429	643	260
Cash, cash equivalents, and restricted cash at end of period	$ 679	$ 429	$ 643
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: beneficial conversion feature (Note1)	$ —	$ 296	$ —
Non-cash transaction: deemed dividend convertible preferred stock (Note 1)	$ —	$ (296)	$ —
Cash paid during the year-			
Interest (net of amounts capitalized)	$ 960	$ 1,071	$ 1,039
Income taxes, net of refunds	$ 12	$ 49	$ 53

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

FIRSTENERGY CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

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

FE was incorporated under Ohio law in 1996. FE’s principal business is the holding, directly or indirectly, of all of the outstanding equity of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, AE Supply, MP, AGC, 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: AESC, FirstEnergy Properties, Inc., FEV, FELHC, Inc., GPUN, Allegheny Ventures, Inc., and Suvon, LLC doing business as both FirstEnergy Home and FirstEnergy Advisors.

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.

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

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

Certain prior year amounts have been reclassified to conform to the current year presentation.

FES and FENOC Chapter 11 Filing

On March 31, 2018, the FES Debtors 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 (which is referred to throughout as the FES Bankruptcy). As a result of the bankruptcy filings, FirstEnergy concluded that it no longer had a controlling interest in the FES Debtors as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, the FES Debtors were deconsolidated from FirstEnergy’s consolidated financial statements. Since such time, FE has accounted and will account for its investments in the FES Debtors at fair values of zero. FE concluded that in connection with the disposal, FES and FENOC became discontinued operations. See Note 3, "Discontinued Operations," for additional information.

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 the FES Key Creditor Groups against FirstEnergy, and includes the following terms, among others:

- FE will pay certain pre-petition FES Debtors 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 Railway Company/CSX Transportation, Inc. rail settlement guarantee, and the FES Debtors' unfunded pension obligations.
- The nonconsensual release of all claims against FirstEnergy by the FES Debtors' creditors, which was subsequently waived pursuant to the Waiver Agreement, discussed below.
- A $225 million cash payment from FirstEnergy.
- An additional $628 million cash payment from FirstEnergy, 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. On November 21, 2019, FirstEnergy, the FES Debtors, the UCC, and the FES Key Creditors Group entered into an amendment to the settlement agreement, which among other things, changed the $628 million

note issuance, into a cash payment to be made upon emergence. The amendment was approved by the Bankruptcy Court on December 16, 2019.

- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continues to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. In addition, FE provides guarantees for certain retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility. On January 21, 2020, AE Supply, FG and a newly formed subsidiary of FG, entered into a letter agreement authorizing the transfer of Pleasants Power Station prior to the FES Debtors’ emergence from bankruptcy. The letter agreement was approved by the Bankruptcy Court on January 28, 2020. The transfer of the Pleasants Power Station was completed on January 30, 2020.
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit for 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.
- Subject to a cap, FirstEnergy has agreed to fund a pension enhancement through its pension plan for voluntary enhanced retirement packages offered to certain FES employees, as well as offer certain other employee benefits (approximately $14 million recognized for the year ending December 31, 2019).
- 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. Based on the 2018 federal tax return filed in September 2019, FirstEnergy owes the FES debtors approximately $31 million associated with 2018, which will be paid upon emergence. Based on current estimates for the 2019 tax return to be filed in 2020, FirstEnergy estimates that it owes the FES Debtors approximately $83 million of which FirstEnergy has paid $14 million as of December 31, 2019. The estimated amounts owed to the FES Debtors for 2018 and 2019 tax returns excludes amounts allocated for non-deductible interest as discussed in Note 3, "Discontinued Operations." FirstEnergy is currently reconciling tax matters under the Intercompany Tax Allocation Agreement with the FES Debtors.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions. 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.

As contemplated under the FES Bankruptcy settlement agreement, AE Supply entered into an agreement on December 31, 2018, to transfer the 1,300 MW Pleasants Power Station and related assets to FG, while retaining certain specified liabilities. Under the terms of the agreement, FG acquired the economic interests in Pleasants as of January 1, 2019, and AE Supply operated Pleasants until it transferred, which, as discussed above, occurred on January 30, 2020. After closing, AE Supply will continue to provide access to the McElroy's Run CCR Impoundment Facility, which was not transferred, and FE will provide guarantees for certain retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility.

On April 11, 2019, the Bankruptcy Court entered an order denying the FES Debtors’ disclosure statement approval motion. The Bankruptcy Court concluded that the nonconsensual third-party releases proposed under the plan of reorganization, which were a condition under the FES Bankruptcy settlement agreement for FirstEnergy’s benefit, were legally impermissible and rendered the plan unconfirmable. On April 18, 2019, FirstEnergy consented to the waiver of the condition. Additionally, the FES Debtors agreed to provide FirstEnergy with the same third-party release provided in favor of certain other parties in any plan of reorganization and to pay FirstEnergy approximately $60 million in cash (paid during the second quarter of 2019) to resolve certain outstanding pension and service charges totaling $87 million, which resulted in FirstEnergy recognizing a $27 million pre-tax charge to income in the first quarter of 2019 ($17 million of which was recognized in continuing operations). Further, the FES Debtors agreed to initiate negotiations with the EPA, OEPA, PA DEP and the NRC to obtain those parties’ cooperation with the FES Debtors’ revised plan of reorganization. FirstEnergy may choose to participate in those negotiations at its option. On May 20, 2019, the Bankruptcy Court approved the waiver and a revised disclosure statement.

In August 2019, the Bankruptcy Court held hearings to consider whether to confirm the FES Debtors’ plan of reorganization. Upon the conclusion of the hearing, the Bankruptcy Court ruled against the objections of several parties, including FERC and OVEC. However, the Bankruptcy Court ruled in favor of the objections made by certain of the FES Debtors’ unions regarding their collective bargaining agreements. The Bankruptcy Court adjourned the hearing without ruling on confirmation and explained that the only issue to be resolved was the acceptance or rejection by the FES Debtors of the collective bargaining agreements at issue.

In October 2019, the FES Debtors and the unions objecting to confirmation of the plan of reorganization reached an agreement framework and the unions agreed to withdraw their objections to the plan of reorganization. On October 15, 2019, the Bankruptcy Court held a hearing to confirm the FES Debtors’ plan of reorganization, and on October 16, 2019, entered a final order confirming the FES Debtors' plan of reorganization. On October 29, 2019, several parties, including FERC, filed notices of appeal with the United States District Court for the Northern District of Ohio appealing the Bankruptcy Court’s final order approving FES Debtors’ plan of reorganization. On December 3, 2019, the NRC provided its approval. The emergence of the FES Debtors from bankruptcy

pursuant to the confirmed plan of reorganization is subject to the satisfaction of certain conditions, including approvals from the FERC.

Restricted Cash

Restricted cash primarily relates to the consolidated VIE's discussed below. The cash collected from JCP&L, MP, PE and the Ohio Companies' customers is used to service debt of their respective funding companies.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities 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.

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

Management assesses the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. Management applies judgment in evaluating the evidence available to assess the probability of recovery of regulatory assets from customers, including, but not limited to evaluating evidence related to precedent for similar items at the Company and information on comparable companies within similar jurisdictions, as well as assessing progress of communications between the Company and regulators. Certain of these regulatory assets, totaling approximately $111 million as of December 31, 2019, are recorded based on prior precedent or anticipated recovery based on rate making premises without a specific order.

The following table provides information about the composition of net regulatory assets and liabilities as of December 31, 2019 and December 31, 2018, and the changes during the year ended December 31, 2019:

Net Regulatory Assets (Liabilities) by Source	December 31, 2019	December 31, 2018	Change
		(In millions)	
Regulatory transition costs	$ (8)	$ 49	$ (57)
Customer payables for future income taxes	(2,605)	(2,725)	120
Nuclear decommissioning and spent fuel disposal costs	(197)	(148)	(49)
Asset removal costs	(756)	(787)	31
Deferred transmission costs	298	170	128
Deferred generation costs	214	202	12
Deferred distribution costs	155	208	(53)
Contract valuations	51	72	(21)
Storm-related costs	551	500	51
Other	36	52	(16)
Net Regulatory Liabilities included on the Consolidated Balance Sheets	$ (2,261)	$ (2,407)	$ 146

The following table provides information about the composition of net regulatory assets that do not earn a current return as of December 31, 2019 and 2018, of which approximately $228 million and $290 million, respectively, are currently being recovered through rates over varying periods depending on the nature of the deferral and the jurisdiction.

Regulatory Assets by Source Not Earning a Current Return	December 31, 2019	December 31, 2018	Change
		(in millions)	
Regulatory transition costs	$ 7	$ 10	$ (3)
Deferred transmission costs	27	80	(53)
Deferred generation costs	15	8	7
Storm-related costs	471	363	108
Other	25	42	(17)
Regulatory Assets Not Earning a Current Return	$ 545	$ 503	$ 42

CUSTOMER RECEIVABLES

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities. There was no material concentration of receivables as of December 31, 2019 and 2018, with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2019 and 2018, net of allowance for uncollectible accounts, are included below. The allowance for uncollectible customer receivables is based on historical loss information comprised of a rolling 36-month average net write-off percentage of revenues.

Customer Receivables	December 31, 2019	December 31, 2018
	(In millions)	
Billed	$ 564	$ 686
Unbilled	527	535
Total	$ 1,091	$ 1,221

EARNINGS (LOSS) PER SHARE OF COMMON STOCK

The convertible preferred stock issued in January 2018 (see Note 11, "Capitalization") is considered participating securities since these shares participate in dividends on common stock on an "as-converted" basis. As a result, EPS of common stock is computed using the two-class method required for participating securities.

The two-class method uses an earnings allocation formula that treats participating securities as having rights to earnings that otherwise would have been available only to common stockholders. Under the two-class method, net income attributable to common stockholders is derived by subtracting the following from income from continuing operations:

- preferred stock dividends,
- deemed dividends for the amortization of the beneficial conversion feature recognized at issuance of the preferred stock (if any), and
- an allocation of undistributed earnings between the common stock and the participating securities (convertible preferred stock) based on their respective rights to receive dividends.

Net losses are not allocated to the convertible preferred stock as they do not have a contractual obligation to share in the losses of FirstEnergy. FirstEnergy allocates undistributed earnings based upon income from continuing operations.

The preferred stock included an embedded conversion option at a price that was below the fair value of the common stock on the commitment date. This beneficial conversion feature, which was approximately $296 million, represents the difference between the fair value per share of the common stock and the conversion price, multiplied by the number of common shares issuable upon conversion. The beneficial conversion feature was amortized as a deemed dividend over the period from the issue date to the first allowable conversion date (July 22, 2018) as a charge to OPIC, since FE is in an accumulated deficit position with no retained earnings to declare a dividend. As noted above, for EPS reporting purposes, this beneficial conversion feature was reflected in net income attributable to common stockholders as a deemed dividend and was fully amortized in 2018.

Basic EPS available to common stockholders is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Participating securities are excluded from basic weighted average ordinary shares outstanding. Diluted EPS available to common stockholders is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding, including all potentially dilutive common shares, if the effect of such common shares is dilutive.

Diluted EPS reflects the dilutive effect of potential common shares from share-based awards and convertible shares of preferred stock. The dilutive effect of outstanding share-based awards is computed using the treasury stock method, which assumes any proceeds that could be obtained upon the exercise of the award would be used to purchase common stock at the average market price for the period. The dilutive effect of the convertible preferred stock is computed using the if-converted method, which assumes conversion of the convertible preferred stock at the beginning of the period, giving income recognition for the add-back of the preferred share dividends, amortization of beneficial conversion feature, and undistributed earnings allocated to preferred stockholders.

Reconciliation of Basic and Diluted EPS of Common Stock	Year Ended December 31, 2019	2018	2017
(In millions, except per share amounts)			
EPS of Common Stock			
Income from continuing operations	$ 904	$ 1,022	$ (289)
Less: Preferred dividends	(3)	(71)	—
Less: Amortization of beneficial conversion feature	—	(296)	—
Less: Undistributed earnings allocated to preferred stockholders[1]	(1)	—	—
Income (loss) from continuing operations available to common stockholders	900	655	(289)
Discontinued operations, net of tax	8	326	(1,435)
Less: Undistributed earnings allocated to preferred stockholders [1]	—	—	—
Income (loss) from discontinued operations available to common stockholders	8	326	(1,435)
Income (loss) attributable to common stockholders, basic	$ 908	$ 981	$ (1,724)
Income allocated to preferred stockholders, preferred dilutive [2]	4	N/A	N/A
Income (loss) attributable to common stockholders, dilutive	$ 912	$ 981	$ (1,724)
Share Count information:			
Weighted average number of basic shares outstanding	535	492	444
Assumed exercise of dilutive stock options and awards	3	2	—
Assumed conversion of preferred stock	4	—	—
Weighted average number of diluted shares outstanding	542	494	444
Income (loss) attributable to common stockholders, per common share:			
Income from continuing operations, basic	$ 1.69	$ 1.33	$ (0.65)
Discontinued operations, basic	0.01	0.66	(3.23)
Income (loss) attributable to common stockholders, basic	$ 1.70	$ 1.99	$ (3.88)
Income from continuing operations, diluted	$ 1.67	$ 1.33	$ (0.65)
Discontinued operations, diluted	0.01	0.66	(3.23)
Income (loss) attributable to common stockholders, diluted	$ 1.68	$ 1.99	$ (3.88)

(1) Undistributed earnings were not allocated to participating securities for the year ended December 31, 2018, as income from continuing operations less dividends declared (common and preferred) and deemed dividends were a net loss. Undistributed earning allocated to participating securities for the year ended December 31, 2019 were immaterial.

(2) The shares of common stock issuable upon conversion of the preferred shares (26 million shares) were not included for 2018 as their inclusion would be anti-dilutive to basic EPS from continuing operations. Amounts allocated to preferred stockholders of $4 million for the year ended December 31,2019 are included within Income from continuing operations available to common stockholders for diluted earnings.

For the years ended December 31, 2018 and 2017, approximately 1 million and 3 million shares from stock options and awards were excluded from the calculation of diluted shares outstanding, respectively, as their inclusion would be antidilutive, and, in the case of 2017, a result of the net loss for the period. For the year ended December 31, 2019, no shares from stock options or awards were excluded from the calculation of diluted shares.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. Property, plant and equipment balances by segment as of December 31, 2019 and 2018, were as follows:

	December 31, 2019				
Property, Plant and Equipment	**In Service[(1)]**	**Accum. Depr.**	**Net Plant**	**CWIP**	**Total**
			(In millions)		
Regulated Distribution	$ 28,735	$ (8,540)	$ 20,195	$ 744	$ 20,939
Regulated Transmission	12,023	(2,383)	9,640	526	10,166
Corporate/Other	1,009	(504)	505	40	545
Total	$ 41,767	$ (11,427)	$ 30,340	$ 1,310	$ 31,650

	December 31, 2018				
Property, Plant and Equipment	**In Service[(1)]**	**Accum. Depr.**	**Net Plant**	**CWIP**	**Total**
			(In millions)		
Regulated Distribution	$ 27,520	$ (8,132)	$ 19,388	$ 628	$ 20,016
Regulated Transmission	11,041	(2,210)	8,831	545	9,376
Corporate/Other	908	(451)	457	62	519
Total	$ 39,469	$ (10,793)	$ 28,676	$ 1,235	$ 29,911

[(1)] Includes finance leases of $163 million and $173 million as of December 31, 2019 and 2018, respectively.

The major classes of Property, plant and equipment are largely consistent with the segment disclosures above. Regulated Distribution has approximately $2 billion of total regulated generation property, plant and equipment.

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite depreciation rates for FirstEnergy were 2.7%, 2.6% and 2.4% in 2019, 2018 and 2017, respectively.

For the years ended December 31, 2019, 2018 and 2017, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $45 million, $46 million and $35 million, respectively, of allowance for equity funds used during construction and $26 million, $19 million and $17 million, respectively, of capitalized interest.

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 16.25% interest (487 MWs) in a 3,003 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, VEPCO, a non-affiliated utility. Net Property, plant and equipment includes $161 million representing AGC's share in this facility as of December 31, 2019. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interests using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statements of Income (Loss). AGC provides the generation capacity from this facility to its owner, MP.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its TMI-2 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, 2019, are described further in Note 13, "Asset Retirement Obligations."

Asset Impairments

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

GOODWILL

In a business combination, the excess of the purchase price over the estimated fair value of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy 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.

FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution and Regulated Transmission. The following table presents goodwill by reporting unit as of December 31, 2019:

	Regulated Distribution	Regulated Transmission	Consolidated
		(In millions)	
Goodwill	$ 5,004	$ 614	$ 5,618

As of July 31, 2019, 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.

INVENTORY

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

DERIVATIVES

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

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivative instruments meeting the normal purchases and normal sales criteria are accounted for under the accrual method of accounting with their effects included in earnings at the time of contract performance.

VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses based on control and economics to determine whether a variable interest classifies FirstEnergy as the primary beneficiary (a controlling financial interest) of a VIE. An enterprise has a controlling financial interest if it has both power and economic control, such that an entity has: (i) the power to direct the activities of a VIE that most significantly

impact the entity's economic performance; and (ii) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

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

Consolidated VIEs

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

- *Ohio Securitization* - In June 2013, SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets.
- *JCP&L Securitization* - JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS.
- *MP and PE Environmental Funding Companies* - Bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE which issued environmental control bonds.

See Note 11, "Capitalization," for additional information on securitized bonds.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- ***Global Holding*** - FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint ventures economic performance. FEV's ownership interest is subject to the equity method of accounting. As of December 31, 2019, the carrying value of the equity method investment was $28 million.

  As discussed in Note 15, "Commitments, Guarantees and Contingencies," FE is the guarantor under Global Holding's $120 million syndicated senior secured term loan facility due November 12, 2024, under which Global Holding's outstanding principal balance is $114 million as of December 31, 2019. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

- ***PATH WV*** - PATH, a proposed transmission line from West Virginia through Virginia into Maryland which PJM cancelled in 2012, is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting. As of December 31, 2019, the carrying value of the equity method investment was $18 million.

- ***Purchase Power Agreements*** - FirstEnergy evaluated its PPAs and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant's variable costs of production.

  FirstEnergy maintains 10 long-term PPAs with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest, or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

  Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contract that may contain a variable interest were $116 million and $108 million, respectively, during the years ended December 31, 2019 and 2018.

- **FES and FENOC** - As a result of the Chapter 11 bankruptcy filing discussed in Note 3, "Discontinued Operations," FE evaluated its investments in FES and FENOC and determined they are VIEs. FE is not the primary beneficiary because it lacks a controlling interest in FES and FENOC, which are subject to the jurisdiction of the Bankruptcy Court as of March 31, 2018. The carrying values of the equity investments in FES and FENOC were zero at December 31, 2019.

NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Pronouncements

ASU 2016-02, *"Leases (Topic 842)"* (Issued February 2016 and subsequently updated to address implementation questions): The new guidance requires 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 implemented a third-party software tool that assisted with the initial adoption and will assist with ongoing compliance. FirstEnergy chose to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Upon adoption, on January 1, 2019, FirstEnergy increased assets and liabilities by $186 million, with no impact to results of operations or cash flows. See Note 8, "Leases," for additional information on FirstEnergy's leases.

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB has not yet been adopted. 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 based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting.

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 expected credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost 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, with early adoption permitted. FirstEnergy has analyzed its financial instruments within the scope of this guidance, primarily trade receivables, AFS debt securities and certain third-party guarantees and does not expect a material impact to its financial statements upon adoption in 2020.

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. FirstEnergy does not expect a material impact to its financial statements upon adoption in 2020.

ASU 2019-12, "*Simplifying the Accounting for Income Taxes*" (Issued in December 2019): ASU 2019-12 enhances and simplifies various aspects of the income tax accounting guidance including the elimination of certain exceptions related to the approach for intraperiod tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. The new guidance also simplifies aspects of the accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. The guidance will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020, with early adoption permitted.

2. REVENUE

FirstEnergy accounts for revenues from contracts with customers under ASC 606, *"Revenue from Contracts with Customers."* Revenue from leases, financial instruments, other contractual rights or obligations and other revenues that are not from contracts with customers are outside the scope of the new standard and accounted for under other existing GAAP. FirstEnergy has elected to exclude sales taxes and other similar taxes collected on behalf of third parties from revenue as prescribed in the new standard. As a result, tax collections and remittances are excluded from recognition in the income statement and instead recorded through the balance sheet. Excise and gross receipts taxes that are assessed on FirstEnergy are not subject to the election and are included in revenue. FirstEnergy has elected the optional invoice practical expedient for most of its revenues and, with the exception of JCP&L transmission, 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.

FirstEnergy's revenues are primarily derived from electric service provided by the Utilities and Transmission Companies. The following tables represent a disaggregation of revenue from contracts with customers for the year ended December 31, 2019, by type of service from each reportable segment:

Revenues by Type of Service	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments (1)	Total
		(In millions)		
Distribution services(2)	$ 5,133	$ —	$ (83)	$ 5,050
Retail generation	3,727	—	(57)	3,670
Wholesale sales(2)	411	—	12	423
Transmission(2)	—	1,510	—	1,510
Other	150	—	2	152
Total revenues from contracts with customers	$ 9,421	$ 1,510	$ (126)	$ 10,805
ARP	181	—	—	181
Other non-customer revenue	96	16	(63)	49
Total revenues	$ 9,698	$ 1,526	$ (189)	$ 11,035

(1) Includes eliminations and reconciling adjustments of inter-segment revenues.
(2) Includes reductions to revenue related to amounts subject to refund resulting from the Tax Act ($16 million at Regulated Distribution and $19 million at Regulated Transmission).

The following tables represent a disaggregation of revenue from contracts with customers for the year ended December 31, 2018, by type of service from each reportable segment:

Revenues by Type of Service	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments (1)	Total
		(In millions)		
Distribution services(2)	$ 5,159	$ —	$ (104)	$ 5,055
Retail generation	3,936	—	(54)	3,882
Wholesale sales(2)	502	—	22	524
Transmission(2)	—	1,335	—	1,335
Other	144	—	4	148
Total revenues from contracts with customers	$ 9,741	$ 1,335	$ (132)	$ 10,944
ARP	254	—	—	254
Other non-customer revenue	108	18	(63)	63
Total revenues	$ 10,103	$ 1,353	$ (195)	$ 11,261

(1) Includes eliminations and reconciling adjustments of inter-segment revenues.
(2) Includes $147 million in net reductions to revenue related to amounts subject to refund resulting from the Tax Act ($131 million at Regulated Distribution and $16 million at Regulated Transmission).

Other non-customer revenue includes revenue from late payment charges of $37 million and $39 million, as well as revenue from derivatives of $8 million and $18 million, respectively, for the years ended December 31, 2019 and 2018.

Regulated Distribution

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies and also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. Each of the Utilities earns revenue from state-regulated rate tariffs under which it provides distribution services to residential, commercial and industrial customers in its service territory. The Utilities are obligated under the regulated construct to deliver power to customers reliably, as it is needed, which creates an implied monthly contract with the end-use customer. See Note 14 "Regulatory Matters," for additional information on rate recovery mechanisms. Distribution and electric revenues are recognized over time as electricity is distributed and delivered to the customer and the customers consume the electricity immediately as delivery occurs.

Retail generation sales relate to POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland, as well as generation sales in West Virginia that are regulated by the WVPSC. 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 varies depending on the level of shopping that occurs. Supply plans vary by state and by service territory. Default service for the Ohio Companies, Pennsylvania Companies, JCP&L and PE's Maryland jurisdiction are provided through a competitive procurement process approved by each state's respective commission. Retail generation revenues are recognized over time as electricity is delivered and consumed immediately by the customer.

The following table represents a disaggregation of the Regulated Distribution segment revenue from contracts with **distribution service and retail generation** customers for the years ended December 31, 2019 and 2018, by class:

	For the Years Ended December 31,	
Revenues by Customer Class	**2019**	**2018**
	(In millions)	
Residential	$ 5,412	$ 5,598
Commercial	2,252	2,350
Industrial	1,106	1,056
Other	90	91
Total	$ 8,860	$ 9,095

Wholesale sales primarily consist of generation and capacity sales into the PJM market from FirstEnergy's regulated electric generation capacity and NUGs. Certain of the Utilities may also purchase power in the PJM markets to supply power to their customers. Generally, these power sales from generation and purchases to serve load are netted hourly and reported gross as either revenues or purchased power on the Consolidated Statements of Income (Loss) based on whether the entity was a net seller or buyer each hour. Capacity revenues are recognized ratably over the PJM planning year at prices cleared in the annual PJM Reliability Pricing Model Based Residual Auction and incremental auctions. Capacity purchases and sales through PJM capacity auctions are reported within revenues on the Consolidated Statements of Income (Loss). Certain capacity income (bonuses) and charges (penalties) related to the availability of units that have cleared in the auctions are unknown and not recorded in revenue until, and unless, they occur.

The Utilities' distribution customers are metered on a cycle basis. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities accrue the estimated unbilled amount as revenue and reverse the related prior period estimate. Customer payments vary by state but are generally due within 30 days.

ASC 606 excludes industry-specific accounting guidance for recognizing revenue from ARPs as these programs represent contracts between the utility and its regulators, as opposed to customers. Therefore, revenue from these programs are not within the scope of ASC 606 and regulated utilities are permitted to continue to recognize such revenues in accordance with existing practice but are presented separately from revenue arising from contracts with customers. FirstEnergy currently has ARPs in Ohio, primarily under Rider DMR, and in New Jersey. Please see Note 14, "Regulatory Matters," for further discussion on Rider DMR.

Regulated Transmission

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. Revenue requirements under stated rates are calculated annually by multiplying the highest one-hour peak load in each respective transmission zone by the approved, stated rate in that zone. Revenues and cash receipts for the stand-ready obligation of providing transmission service are recognized ratably over time.

Effective January 1, 2018, JCP&L is subject to a FERC-approved settlement agreement that provides an annual revenue requirement of $155 million, which is recognized ratably as revenue over time. Please see Note 14, "Regulatory Matters," for further discussion on tariff amendments approved by FERC on December 19, 2019, to convert JCP&L's existing stated transmission rate to a forward-looking formula transmission rate.

The following table represents a disaggregation of revenue from contracts with regulated transmission customers by transmission owner for the years ended December 31, 2019 and 2018 by transmission owner:

	For the Years Ended December 31,	
Transmission Owner	**2019**	**2018**
	(In millions)	
ATSI	$ 754	$ 664
TrAIL	242	237
MAIT	224	150
Other	290	284
Total Revenues	$ 1,510	$ 1,335

3. DISCONTINUED OPERATIONS

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. Prior period results have been reclassified to conform with such presentation as discontinued operations.

FES and FENOC Chapter 11 Bankruptcy Filing

As discussed in Note 1, "Organization and Basis of Presentation," on March 31, 2018, FES and FENOC announced the FES Bankruptcy. FirstEnergy concluded that it no longer had a controlling interest in the FES Debtors, as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, the FES Debtors were deconsolidated from FirstEnergy's consolidated financial statements, and FirstEnergy has accounted and will account for its investments in the FES Debtors at fair values of zero. In connection with the disposal and the FES Bankruptcy settlement agreement approved by the Bankruptcy Court in September 2018, as further discussed in Note 1, "Organization and Basis of Presentation," FE recorded an after-tax gain on disposal of $59 million and $435 million in 2019 and 2018, respectively.

By eliminating a significant portion of its competitive generation fleet with the deconsolidation of the FES Debtors, FirstEnergy has concluded the FES Debtors meet the criteria for discontinued operations, as this represents a significant event in management's strategic review to exit commodity-exposed generation and transition to a fully regulated company.

FES Borrowings from FE

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 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, FE will release any and all claims against the FES Debtors with respect to the $500 million borrowed under the secured credit facility.

On March 16, 2018, the FES Debtors withdrew from the unregulated companies' money pool, which included FE, and the FES Debtors. Under the terms of the FES Bankruptcy settlement agreement, FE reinstated $88 million for 2018 estimated payments for NOLs applied against the FES Debtor's position in the unregulated companies' money pool prior to their withdrawal on March 16, 2018, which increased the amount the FES Debtors owed FE under the money pool to $92 million. In addition, as of March 31, 2018, AE Supply had a $102 million outstanding unsecured promissory note owed from FES. Following deconsolidation of the FES Debtors on March 31, 2018, and given the terms of the FES Bankruptcy settlement agreement, FE fully reserved the $92 million associated with the outstanding unsecured borrowings under the unregulated companies' money pool and the $102 million associated with the AE Supply unsecured promissory note. Under the terms of the FES Bankruptcy settlement agreement, FirstEnergy will release any and all claims against the FES Debtors with respect to the $92 million owed under the unregulated money pool and $102 million unsecured promissory note. For the years ended December 31, 2019 and 2018, approximately $33 million and $24 million of interest was accrued and subsequently reserved, respectively.

Services Agreements

Pursuant to the FES Bankruptcy settlement agreement, FirstEnergy entered into an amended and restated shared services agreement with the FES Debtors to extend the availability of shared services until no later than June 30, 2020, subject to reductions in services if requested by the FES Debtors. Under the amended shared services agreement, and consistent with the prior shared services agreements, costs are directly billed or assigned at no more than cost. In addition to providing for certain notice requirements and other terms and conditions, the agreement provided for a credit to the FES Debtors in an amount up to $112.5 million for charges incurred for services provided under prior shared services agreements and the amended shared services agreement from April 1, 2018 through December 31, 2018. The entire credit for shared services provided to the FES Debtors ($112.5 million) has been recognized by FE and was included within the loss from discontinued operations as of December 31, 2018. The FES Debtors have paid approximately $152 million for the shared services for the year ended December 31, 2019.

Benefit Obligations

FirstEnergy will retain certain obligations for the FES Debtors' employees for services provided prior to emergence from bankruptcy. The retention of this obligation at March 31, 2018, resulted in a net liability of $820 million (including EDCP, pension and OPEB) with a corresponding loss from discontinued operations. EDCP and pension/OPEB service costs earned by the FES Debtors' employees during bankruptcy are billed under the shared services agreement. As FE continues to provide pension benefits to FES/FENOC employees, certain components of pension cost, including the mark to market, are seen as providing ongoing services and are reported in the continuing operations of FE, subsequent to the bankruptcy filing. FE has billed the FES Debtors approximately $37 million for their share of pension and OPEB service costs for the year ended December 31, 2019.

Purchase Power

FES at times provides power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements and provides power to certain affiliates' facilities. As of December 31, 2019, the Utilities owed FES approximately $10 million related to these purchases. The terms and conditions of the power purchase agreements are generally consistent with industry practices and other similar third-party arrangements. The Utilities purchased and recognized in continuing operations approximately $171 million and $318 million of power purchases from FES for the years ended December 31, 2019 and 2018, respectively.

Income Taxes

For U.S. federal income taxes, until emergence from bankruptcy, the FES Debtors will continue to be consolidated in FirstEnergy’s tax return and taxable income will be determined based on the tax basis of underlying individual net assets. Deferred taxes previously recorded on the inside basis differences may not represent the actual tax consequence for the outside basis difference, causing a recharacterization of an existing consolidated-return NOL as a future worthless stock deduction. FirstEnergy currently estimates a future worthless stock deduction of approximately $4.8 billion ($1.0 billion, net of tax) and is net of unrecognized tax benefits of $448 million ($94 million, net of tax). The estimated worthless stock deduction is contingent upon the emergence of the FES Debtors from the FES Bankruptcy and such amounts may be materially impacted by future events.

Additionally, the Tax Act amended Section 163(j) of the Code, limiting interest expense deductions for corporations but with exemption for certain regulated utilities. On November 26, 2018, the IRS issued proposed regulations implementing Section 163(j), including application 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 2019 and 2018 and has recorded a deferred tax asset on the nondeductible portion as it is carried forward with an indefinite life. However, the deferred tax asset related to the carryforward of nondeductible interest has a full valuation allowance recorded against it as future profitability from sources other than regulated utility businesses is required for utilization. In 2019 and 2018, FirstEnergy recorded tax expense of $54 million and $60 million, respectively, resulting from the valuation allowance, of which $14 million and $27 million has been reflected as an uncertain tax position in 2019 and 2018, respectively. All tax expense related to nondeductible interest in 2019 and 2018 has been recorded in discontinued operations as it is entirely attributed to the inclusion of the FES Debtors in FirstEnergy's consolidated group and therefore, pursuant to the Intercompany Tax Sharing Agreement, has been allocated to the FES Debtors. FE has fully reserved the amount of non-deductible interest allocated to the FES Debtors in connection with the on-going reconciliations under the Intercompany Tax Allocation Agreement with the FES Debtors.

See Note 1, "Organization and Basis of Presentation," for further discussion of the settlement among FirstEnergy, the FES Key Creditor Groups, the FES Debtors and the UCC.

Competitive Generation Asset Sales

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement with a subsidiary of LS Power Equity Partners III, LP, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity). On December 13, 2017, AE Supply completed the sale of the natural gas generating plants. On March 1, 2018, AE Supply completed the sale of the Buchanan Generating Facility. On May 3, 2018, AE Supply and AGC completed the sale of approximately 59% of AGC's interest in Bath County. Also, on May 3, 2018, following the closing of the sale by AGC of a portion of its ownership interest in Bath County, AGC completed the redemption of AE Supply's shares in AGC and AGC became a wholly owned subsidiary of MP.

On March 9, 2018, BSPC and FG entered into an asset purchase agreement with Walleye Power, LLC (formerly Walleye Energy, LLC), for the sale of the Bay Shore Generating Facility, including the 136 MW Bay Shore Unit 1 and other retired coal-fired generating equipment owned by FG. The Bankruptcy Court approved the sale on July 13, 2018, and the transaction was completed on July 31, 2018.

As contemplated under the FES Bankruptcy settlement agreement, AE Supply entered into an agreement on December 31, 2018, to transfer the 1,300 MW Pleasants Power Station and related assets to FG, while retaining certain specified liabilities. Under the terms of the agreement, FG acquired the economic interests in Pleasants as of January 1, 2019, and AE Supply operated Pleasants until it transferred, which, as discussed above, occurred on January 30, 2020. After closing, AE Supply will continue to provide access to the McElroy's Run CCR Impoundment Facility, which was not transferred, and FE will provide guarantees for certain retained environmental liabilities of AE Supply, including the McElroy's Run CCR Impoundment Facility.

Individually, the AE Supply and BSPC asset sales and Pleasants Power Station transfer did not qualify for reporting as discontinued operations. However, in the aggregate, the transactions were part of management's strategic review to exit commodity-exposed generation and, when considered with FES' and FENOC's bankruptcy filings on March 31, 2018, represent a collective elimination of substantially all of FirstEnergy's competitive generation fleet and meet the criteria for discontinued operations.

Summarized Results of Discontinued Operations

Summarized results of discontinued operations for the years ended December 31, 2019, 2018, and 2017 were as follows:

	For the Years Ended December 31,		
(In millions)	**2019**	**2018 [(3)]**	**2017 [(3)]**
Revenues	$ 188	$ 989	$ 3,055
Fuel	(140)	(304)	(879)
Purchased power	—	(84)	(268)
Other operating expenses	(63)	(435)	(1,499)
Provision for depreciation	—	(96)	(109)
General taxes	(14)	(35)	(103)
Impairment of assets[(1)]	—	—	(2,358)
Pleasants economic interest[(2)]	27	—	—
Other expense, net	(2)	(83)	(94)
Loss from discontinued operations, before tax	(4)	(48)	(2,255)
Income tax expense (benefit)	47	61	(820)
Loss from discontinued operations, net of tax	(51)	(109)	(1,435)
Gain on disposal of FES and FENOC, net of tax	59	435	—
Income (Loss) from discontinued operations	$ 8	$ 326	$ (1,435)

[(1)] Includes impairment of the FES nuclear facilities, the Pleasants Power Station ($120 million), and the competitive generation asset sale ($193 million).
[(2)] Reflects the estimated amounts owed from FG for its economic interests in Pleasants effective January 1, 2019, as further discussed above.
[(3)] Discontinued operations include results of FES and FENOC through March 31, 2018, when deconsolidated from FirstEnergy's financial statements.

The gain on disposal that was recognized in the year ended December 31, 2019 and 2018, consisted of the following:

	For the Years Ended December 31,	
(In millions)	**2019**	**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	7	(1,197)
Loss on disposal of FES and FENOC, before tax	7	(877)
Income tax benefit, including estimated worthless stock deduction	52	1,312
Gain on disposal of FES and FENOC, net of tax	$ 59	$ 435

As of December 31, 2019 and 2018, materials and supplies of $33 million and $25 million, respectively, are included in FirstEnergy's Consolidated Balance Sheets as Current assets - discontinued operations.

FirstEnergy's Consolidated Statements of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each cash flow category. The following table summarizes the major classes of cash flow items from discontinued operations for the years ended December 31, 2019, 2018 and 2017:

	For the Years Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income from discontinued operations	$ 8	$ 326	$ (1,435)
Gain on disposal, net of tax	(59)	(435)	—
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	—	110	333
Deferred income taxes and investment tax credits, net	47	61	(842)
Unrealized (gain) loss on derivative transactions	—	(10)	81
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	—	(27)	(317)
Nuclear fuel	—	—	(254)
Sales of investment securities held in trusts	—	109	940
Purchases of investment securities held in trusts	—	(122)	(999)

4. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the years ended December 31, 2019, 2018 and 2017, for FirstEnergy are shown in the following table:

	Gains & Losses on Cash Flow Hedges [(1)]	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2017	$ (28)	$ 52	$ 150	$ 174
Other comprehensive income before reclassifications	—	85	(11)	74
Amounts reclassified from AOCI	10	(63)	(74)	(127)
Other comprehensive income (loss)	10	22	(85)	(53)
Income tax (benefits) on other comprehensive income (loss)	4	7	(32)	(21)
Other comprehensive income (loss), net of tax	6	15	(53)	(32)
AOCI Balance, December 31, 2017	$ (22)	$ 67	$ 97	$ 142
Other comprehensive income before reclassifications	—	(97)	(9)	(106)
Amounts reclassified from AOCI	8	(1)	(74)	(67)
Deconsolidation of FES and FENOC	13	(8)	—	5
Other comprehensive income (loss)	21	(106)	(83)	(168)
Income tax (benefits) on other comprehensive income (loss)	10	(39)	(38)	(67)
Other comprehensive income (loss), net of tax	11	(67)	(45)	(101)
AOCI Balance, December 31, 2018	$ (11)	$ —	$ 52	$ 41
Other comprehensive income				

before reclassifications	—	—	(2)	(2)
Amounts reclassified from AOCI	2	—	(29)	(27)
Other comprehensive income (loss)	2	—	(31)	(29)
Income tax (benefits) on other comprehensive income (loss)	—	—	(8)	(8)
Other comprehensive income (loss), net of tax	2	—	(23)	(21)
AOCI Balance, December 31, 2019	$ (9)	$ —	$ 29	$ 20

[1] Relates to previous cash flow hedges used to hedge fixed rate long-term debt securities prior to their issuance.

The following amounts were reclassified from AOCI for FirstEnergy in the years ended December 31, 2019, 2018 and 2017:

Reclassifications from AOCI [1]	Year Ended December 31, 2019	2018 [2]	2017	Affected Line Item in Consolidated Statements of Income (Loss)
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ —	$ 1	$ 2	Other operating expenses
Long-term debt	2	7	8	Interest expense
	—	(2)	(4)	Income taxes
	$ 2	$ 6	$ 6	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ —	$ (1)	$ (40)	Discontinued operations
Defined benefit pension and OPEB plans				
Prior-service costs	$ (29)	$ (74)	$ (74)	[3]
	8	19	28	Income taxes
	$ (21)	$ (55)	$ (46)	Net of tax

[1] Amounts in parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

[2] Includes stranded tax amounts reclassified from AOCI in connection with the adoption of ASU 2018-02, "*Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*".

[3] Prior-service costs are reported within Miscellaneous income, net within Other Income (Expense) on FirstEnergy's Consolidated Statements of Income (Loss). Components are included in the computation of net periodic cost (credits), see Note 5, "Pension and Other Postemployment Benefits," for additional details.

5. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. Under the cash-balance portion of the Pension Plan (for employees hired on or after January 1, 2014), FirstEnergy makes contributions to eligible employee retirement accounts based on a pay credit and an interest credit. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pension and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy recognizes a pension and OPEB mark-to-market adjustment for the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2019, 2018, and 2017 were $676 million, $145 million, and $141 million, respectively. Of these amounts, approximately $2 million, $1 million, and $39 million, are included in discontinued operations for the years ended December 31, 2019, 2018, and 2017, respectively. In 2019, the pension and OPEB mark-to-market adjustment primarily reflects a 110 bps decrease in the discount rate used to measure benefit obligations and higher than expected asset returns.

FirstEnergy’s pension and OPEB 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. FirstEnergy expects no required contributions through 2021.

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

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2019, FirstEnergy's pension and OPEB plan assets experienced gains of $1,492 million, or 20.2%, compared to losses of $371 million, or (4.0)%, in 2018 and gains of $999 million, or 15.1%, in 2017, and assumed a 7.50% rate of return for 2019, 2018 and 2017 which generated $569 million, $605 million and $478 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 decrease or increase future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

During 2019, the Society of Actuaries published new mortality tables that include more current data than the RP-2014 tables as well as new improvement scales. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the Pri-2012 mortality table with projection scale MP-2019 was most appropriate. As such, the Pri-2012 mortality table with projection scale MP-2019 was utilized to determine the 2019 benefit cost and obligation as of December 31, 2019 for the FirstEnergy pension and OPEB plans. The impact of using the Pri-2012 mortality table with projection scale MP-2019 resulted in a decrease to the projected benefit obligation approximately $29 million and $3 million for the pension and OPEB plans, respectively, and was included in the 2019 pension and OPEB mark-to-market adjustment.

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 election is considered a change in estimate and, accordingly, accounted for prospectively, and did not have a material impact on FirstEnergy's financial statements.

Following adoption of ASU 2017-07, "*Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*" in 2018, service costs, net of capitalization, continue to be reported within Other operating expenses on the FirstEnergy Consolidated Statements of Income (Loss). Non-service costs are reported within Miscellaneous income, net, within Other Income (Expense).

Obligations and Funded Status - Qualified and Non-Qualified Plans	Pension 2019	Pension 2018	OPEB 2019	OPEB 2018
	(In millions)			
Change in benefit obligation:				
Benefit obligation as of January 1	$ 9,462	$ 10,167	$ 608	$ 731
Service cost	193	224	3	5
Interest cost	373	372	22	25
Plan participants' contributions	—	—	4	3
Plan amendments	2	5	—	5
Special termination benefits	14	31	—	8
Medicare retiree drug subsidy	—	—	1	1
Annuity purchase	—	(129)	—	—
Actuarial (gain) loss	1,535	(710)	64	(121)
Benefits paid	(529)	(498)	(48)	(49)
Benefit obligation as of December 31	$ 11,050	$ 9,462	$ 654	$ 608
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$ 6,984	$ 6,704	$ 408	$ 439
Actual return on plan assets	1,419	(363)	73	(8)
Annuity purchase	—	(129)	—	—
Company contributions	521	1,270	21	22
Plan participants' contributions	—	—	4	3
Benefits paid	(529)	(498)	(48)	(48)
Fair value of plan assets as of December 31	$ 8,395	$ 6,984	$ 458	$ 408
Funded Status:				
Qualified plan	$ (2,203)	$ (2,093)	$ —	$ —
Non-qualified plans	(452)	(385)	—	—
Funded Status (Net liability as of December 31)	$ (2,655)	$ (2,478)	$ (196)	$ (200)
Accumulated benefit obligation	$ 10,439	$ 8,951	$ —	$ —
Amounts Recognized in AOCI:				
Prior service cost (credit)	$ 24	$ 30	$ (85)	$ (121)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	3.34%	4.44%	3.18%	4.30%
Rate of compensation increase	4.10%	4.10%	N/A	N/A
Cash balance weighted average interest crediting rate	2.57%	3.34%	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	6.0-5.5%	6.0-5.5%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.5%	4.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2028	2028
Allocation of Plan Assets (as of December 31)				
Equity securities	29%	34%	54%	48%
Fixed Income	36%	34%	30%	35%
Hedge funds	9%	11%	—%	—%

Insurance-linked securities	2%	2%	—%	—%
Real estate funds	7%	10%	—%	—%
Derivatives	—%	2%	—%	—%
Private equity funds	4%	2%	—%	—%
Cash and short-term securities	13%	5%	16%	17%
Total	100%	100%	100%	100%

Components of Net Periodic Benefit Costs for the Years Ended December 31,	Pension			OPEB		
	2019	2018	2017	2019	2018	2017
	(In millions)					
Service cost	$ 193	$ 224	$ 208	$ 3	$ 5	$ 5
Interest cost	373	372	390	22	25	27
Expected return on plan assets	(540)	(574)	(448)	(29)	(31)	(30)
Amortization of prior service costs (credits)	7	7	7	(36)	(81)	(81)
Special termination costs [(1)]	14	31	—	—	8	—
Pension & OPEB mark-to-market adjustment	656	227	108	20	(82)	13
Net periodic benefit costs (credits)	$ 703	$ 287	$ 265	$ (20)	$ (156)	$ (66)

[(1)] Subject to a cap, FirstEnergy has agreed to fund a pension enhancement through its pension plan, for voluntary enhanced retirement packages offered to certain FES employees, as well as offer certain other employee benefits (approximately $14 million recognized for the year ended December 31, 2019).

Assumptions Used to Determine Net Periodic Benefit Cost for the Years Ended December 31,*	Pension			OPEB		
	2019	2018	2017	2019	2018	2017
Weighted-average discount rate	4.44%	3.75%	4.25%	4.30%	3.50%	4.00%
Expected long-term return on plan assets	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Rate of compensation increase	4.10%	4.20%	4.20%	N/A	N/A	N/A

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

Amounts in the tables above include FES Debtors' share of the net periodic pension and OPEB costs (credits) of $242 million and $(19) million, respectively, for the year ended December 31, 2019. The FES Debtors' share of the net periodic pension and OPEB costs (credits) were $64 million and $(25) million, respectively, for the year ended December 31, 2018, and $60 million and $(17) million, respectively, for the year ended December 31, 2017. The 2019 special termination costs associated with FES' voluntary enhanced retirement package are a component of Discontinued operations in FirstEnergy's Consolidated Statements of Income (Loss). Following the FES Debtors' voluntary bankruptcy filing, FE has billed the FES Debtors approximately $37 million and $42 million for their share of pension and OPEB service costs for the years ended December 31, 2019 and 2018, respectively.

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

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 10, "Fair Value Measurements," for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2019 and 2018.

	December 31, 2019				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 1,069	$ —	$ 1,069	13%
Equities	1,532	828	—	2,360	29%
Fixed income:					
Corporate bonds	—	2,064	—	2,064	25%
Other[3]	—	880	—	880	11%
Alternatives:					
Derivatives	(40)	—	—	(40)	—%
Total [1]	$ 1,492	$ 4,841	$ —	$ 6,333	78%
Private equity funds [2]				342	4%
Insurance-linked securities [2]				186	2%
Hedge funds [2]				774	9%
Real estate funds [2]				584	7%
Total Investments				$ 8,219	100%

(1) Excludes $176 million as of December 31, 2019, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.
(2) Net Asset Value used as a practical expedient to approximate fair value.
(3) Includes insurance annuities, bank loans and emerging markets debt.

	December 31, 2018				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 342	$ —	$ 342	5%
Equities	1,115	1,256	—	2,371	34%
Fixed income:					
Government bonds	—	59	—	59	1%
Corporate bonds	—	1,674	—	1,674	23%
Other[4]	—	667	—	667	10%
Alternatives:					
Derivatives	108	—	—	108	2%
Total [1]	$ 1,223	$ 3,998	$ —	$ 5,221	75%
Private equity funds [2]				143	2%
Insurance-linked securities [2]				108	2%
Hedge funds [3]				779	11%
Real estate funds [3]				665	10%
Total Investments				$ 6,916	100%

(1) Excludes $68 million as of December 31, 2018, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.
(2) Net asset value used as a practical expedient to approximate fair value.
(3) The classification of Level 2 and 3 assets from the prior year, $779 million and $665 million, respectively, was adjusted in the current year presentation and included outside of the fair value hierarchy table as of December 31, 2018, as investments for which Net Asset Value is used as a practical expedient to approximate fair value in accordance with ASU 2015-07 "*Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*".
(4) Includes insurance annuities, bank loans and emerging markets debt.

As of December 31, 2019 and 2018, the OPEB trust investments measured at fair value were as follows:

	December 31, 2019				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 72	$ —	$ 72	16%
Equity investment:					
Domestic	246	—	—	246	54%
Fixed income:					
Government bonds	—	100	—	100	22%
Corporate bonds	—	34	—	34	7%
Mortgage-backed securities (non-government)		5	—	5	1%
Total [(1)]	$ 246	$ 211	$ —	$ 457	100%

[(1)] Excludes $1 million as of December 31, 2019, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2018				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 71	$ —	$ 71	17%
Equity investment:					
Domestic	196	—	—	196	48%
Fixed income:					
Government bonds	—	107	—	107	26%
Corporate bonds	—	32	—	32	8%
Mortgage-backed securities (non-government)		4	—	4	1%
Total [(1)]	$ 196	$ 214	$ —	$ 410	100%

[(1)] Excludes $(2) million as of December 31, 2018, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

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

FirstEnergy’s target asset allocations for its pension and OPEB trust portfolios for 2019 and 2018 are shown in the following table:

	Target Asset Allocations	
	2019	2018
Equities	38%	38%
Fixed income	30%	30%
Hedge funds	8%	8%
Real estate	10%	10%
Alternative investments	8%	8%
Cash	6%	6%
	100%	100%

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

	Pension	OPEB Benefit Payments	OPEB Subsidy Receipts
		(In millions)	
2020	$ 547	$ 52	$ (1)
2021	564	49	(1)
2022	573	48	(1)
2023	586	47	(1)
2024	593	46	(1)
Years 2025-2029	3,099	208	(3)

6. STOCK-BASED COMPENSATION PLANS

FirstEnergy grants stock-based awards through the ICP 2015, primarily in the form of restricted stock and performance-based restricted stock units. Under FirstEnergy's previous incentive compensation plan, the ICP 2007, FirstEnergy also granted stock options and performance shares. The ICP 2007 and ICP 2015 include shareholder authorization to issue 29 million shares and 10 million shares, respectively, of common stock or their equivalent. As of December 31, 2019, approximately 3.9 million shares were available for future grants under the ICP 2015 assuming maximum performance metrics are achieved for the outstanding cycles of restricted stock units. No shares are available for future grants under the ICP 2007. Shares not issued due to forfeitures or cancellations may be added back to the ICP 2015. Shares granted under the ICP 2007 and ICP 2015 are issued from authorized but unissued common stock. Vesting periods for stock-based awards range from one to ten years, with the majority of awards having a vesting period of three years. FirstEnergy also issues stock through its 401(k) Savings Plan, EDCP, and DCPD. Currently, FirstEnergy records the compensation costs for stock-based compensation awards that will be paid in stock over the vesting period based on the fair value on the grant date. FirstEnergy accounts for forfeitures as they occur.

FirstEnergy adjusts the compensation costs for stock-based compensation awards that will be paid in cash based on changes in the fair value of the award as of each reporting date. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or settled. Actual income tax benefits realized during the years ended December 31, 2019, 2018 and 2017, were $24 million, $15 million and $15 million, respectively. The income tax effects of awards are recognized in the income statement when the awards vest, are settled or are forfeited.

Stock-based compensation costs and the amount of stock-based compensation costs capitalized related to FirstEnergy plans for the years ended December 31, 2019, 2018 and 2017 are included in the following tables:

Stock-based Compensation Plan	For the Years Ended December 31, 2019	2018	2017
		(In millions)	
Restricted Stock Units	$ 73	$ 102	$ 49
Restricted Stock	1	1	1
401(k) Savings Plan	33	33	42
EDCP & DCPD	9	7	6
Total	$ 116	$ 143	$ 98
Stock-based compensation costs capitalized	$ 54	$ 60	$ 37

There was no stock option expense for the years ended December 31, 2019, 2018 and 2017. Income tax benefits associated with stock-based compensation plan expense were $10 million, $18 million and $10 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Restricted Stock Units

Beginning with the performance-based restricted stock units granted in 2015, two-thirds of each award will be paid in stock and one-third will be paid in cash. Restricted stock units payable in stock provide the participant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement, subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets applicable to each award. The grant date fair value of the stock portion of the restricted stock unit award is measured based on the average of the high and low prices of FE common stock on the date of grant. Beginning with awards granted in 2018, restricted stock units include a performance metric consisting of a relative total shareholder return modifier utilizing the S&P 500 Utility Index as a comparator group. The estimated grant date fair value for these awards is calculated using the Monte Carlo simulation method.

Restricted stock units payable in cash provide the participant the right to receive cash based on the number of stock units set forth in the agreement and value of the equivalent number of shares of FE common stock as of the vesting date. The cash portion of the restricted stock unit award is considered a liability award, which is remeasured each period based on FE's stock price and projected performance adjustments. The liability recorded for the portion of performance-based restricted stock units payable in cash in the future as of December 31, 2019, was $46 million. During 2019, approximately $44 million was paid in relation to the cash portion of restricted stock unit obligations that vested in 2019.

The vesting period for the performance-based restricted stock unit awards granted in 2017, 2018 and 2019, were each three years. Dividend equivalents are received on the restricted stock units and are reinvested in additional restricted stock units and subject to the same performance conditions as the underlying award.

Restricted stock unit activity for the year ended December 31, 2019, was as follows:

Restricted Stock Unit Activity	**Shares** ***(in millions)***	**Weighted-Average Grant Date Fair Value (per share)**
Nonvested as of January 1, 2019	3.3	$ 33.78
Granted in 2019	1.9	41.23
Forfeited in 2019	(0.4)	37.23
Vested in 2019[(1)]	(2.2)	40.73
Nonvested as of December 31, 2019	2.6	$ 36.20

[(1)] Excludes dividend equivalents of approximately 636 thousand shares earned during vesting period.

The weighted-average fair value of awards granted in 2019, 2018 and 2017 was $41.23, $36.78 and $31.71 per share, respectively. For the years ended December 31, 2019, 2018, and 2017, the fair value of restricted stock units vested was $91 million, $62 million, and $42 million, respectively. As of December 31, 2019, there was approximately $31 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted for restricted stock units, which is expected to be recognized over a period of approximately three years.

Restricted Stock

Certain employees receive awards of FE restricted stock (as opposed to "units" with the right to receive shares at the end of the restriction period) subject to restrictions that lapse over a defined period of time or upon achieving performance results. The fair value of restricted stock is measured based on the average of the high and low prices of FE common stock on the date of grant. Dividends are received on the restricted stock and are reinvested in additional shares of restricted stock, subject to the vesting conditions of the underlying award. Restricted stock activity for the year ended December 31, 2019, was not material.

Stock Options

Stock options have been granted to certain employees allowing them to purchase a specified number of common shares at a fixed exercise price over a defined period of time. Stock options generally expire ten years from the date of grant. There were no stock options granted in 2019. Stock option activity for the year ended December 31, 2019 was as follows:

Stock Option Activity	**Number of Shares** ***(in millions)***	**Weighted Average Exercise Price (per share)**
Balance, January 1, 2019 (all options exercisable)	0.8	$ 37.37
Options exercised	(0.6)	37.26
Options forfeited	(0.1)	37.72
Balance, December 31, 2019 (all options exercisable)	0.1	$ 37.75

Approximately $23 million and $12 million of cash was received from the exercise of stock options in 2019 and 2018, respectively. There was no cash received from the exercise of stock options in 2017. The weighted-average remaining contractual term of options outstanding as of December 31, 2019, was 2.16 years.

401(k) Savings Plan

In 2019 and 2018, approximately 1 million and 1.3 million shares of FE common stock, respectively, were issued and contributed to participants' accounts.

EDCP

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

DCPD

Under the DCPD, members of FE's Board of Directors can elect to defer all or a portion of their equity retainers to a deferred stock account and their cash retainers to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $9 million as of December 31, 2019 and December 31, 2018, is included in the caption “Retirement benefits,” on the Consolidated Balance Sheets.

7. TAXES

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

FE and its subsidiaries, as well as FES and FENOC, are party to an intercompany income tax allocation agreement that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FE, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FE that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit. FES and FENOC are expected to remain parties to the intercompany tax allocation agreement until their emergence from bankruptcy, which is when they will no longer be part of FirstEnergy's consolidated tax group.

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, effective in 2018;
- 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.

INCOME TAXES[1]	For the Years Ended December 31, 2019	2018	2017
		(In millions)	
Currently payable (receivable)-			
Federal	$ (16)	$ (16)	$ 14
State[2]	24	17	20
	8	1	34
Deferred, net-			
Federal[3]	150	252	1,647
State[4]	60	243	40
	210	495	1,687
Investment tax credit amortization	(5)	(6)	(6)
Total income taxes	$ 213	$ 490	$ 1,715

(1) Income Taxes on Income from Continuing Operations.

(2) Excludes $1 million and $22 million of state tax expense associated with discontinued operations for the years ended December 31, 2018 and 2017, respectively.

(3) Excludes $(9) million, $(1.3) billion and $(771) million of federal tax benefit associated with discontinued operations for the years ended December 31, 2019, 2018 and 2017, respectively.

(4) Excludes $4 million, $12 million and $(69) million of state tax expense (benefit) associated with discontinued operations for the years ended December 31, 2019, 2018 and 2017, respectively.

FirstEnergy tax rates are affected by permanent items, such as AFUDC equity and other flow-through items, as well as discrete items that may occur in any given period, but are not consistent from period to period. The following tables provide a reconciliation of federal income tax expense (benefit) at the federal statutory rate to the total income taxes (benefits) for the years ended December 31, 2019, 2018 and 2017:

	For the Years Ended December 31, 2019	2018	2017
		(In millions)	
Income from Continuing Operations, before income taxes	$ 1,117	$ 1,512	$ 1,426
Federal income tax expense at statutory rate (21%, 21%, and 35% for 2019, 2018, and 2017, respectively)	$ 235	$ 318	$ 499
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	96	90	40
AFUDC equity and other flow-through	(36)	(31)	(15)
Amortization of investment tax credits	(5)	(5)	(6)
ESOP dividend	(3)	(3)	(5)
Remeasurement of deferred taxes	—	24	1,193
WV unitary group remeasurement	—	126	—
Excess deferred tax amortization due to the Tax Act	(74)	(60)	—
Uncertain tax positions	(11)	2	(3)
Valuation allowances	5	21	11
Other, net	6	8	1
Total income taxes	$ 213	$ 490	$ 1,715
Effective income tax rate	19.1%	32.4%	120.3%

FirstEnergy's effective tax rate on continuing operations for 2019 and 2018 was 19.1% and 32.4%, respectively. The decrease in the effective tax rate resulted primarily from the absence of charges that occurred in 2018, including approximately $24 million related to the remeasurement of deferred income taxes resulting from the Tax Act and approximately $126 million associated with the remeasurement of West Virginia state deferred income taxes, resulting from the legal and financial separation of FES and FENOC from FirstEnergy, which occurred in the first quarter of 2018 (see Note 3, "Discontinued Operations" for other tax matters relating to the FES Bankruptcy that were recognized in discontinued operations). In addition, in 2019, FirstEnergy's regulated distribution and transmission subsidiaries recognized an increase in the tax benefit associated with the amortization of net excess deferred income taxes as compared to 2018 (see Note 14, "Regulatory Matters," for additional detail).

Accumulated deferred income taxes as of December 31, 2019 and 2018, are as follows:

	As of December 31,	
	2019	2018
	(In millions)	
Property basis differences	$ 5,037	$ 4,737
Pension and OPEB	(698)	(629)
TMI-2 nuclear decommissioning	89	82
AROs	(226)	(215)
Regulatory asset/liability	445	414
Deferred compensation	(154)	(170)
Estimated worthless stock deduction	(1,007)	(1,004)
Loss carryforwards and AMT credits	(836)	(899)
Valuation reserve	441	394
All other	(242)	(208)
Net deferred income tax liability	$ 2,849	$ 2,502

FirstEnergy has recorded as deferred income tax assets the effect of Federal NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2019, FirstEnergy's loss carryforwards and AMT credits consisted of $2.1 billion ($441 million, net of tax) of Federal NOL carryforwards that will begin to expire in 2031 and Federal AMT credits of $9 million that have an indefinite carryforward period.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $6.8 billion ($361 million, net of tax) for FirstEnergy, of which approximately $1.5 billion ($103 million, net of tax) is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions. In addition to the valuation allowances on state and local NOLs, FirstEnergy has recorded a reserve against certain state and local property related DTAs (approximately $62 million, net of tax) and a reserve against the estimated nondeductible portion of interest expense, discussed above.

Expiration Period	State	Local
	(In millions)	
2020-2024	$ 1,844	$ 1,081
2025-2029	1,652	—
2030-2034	1,265	—
2035-2039	886	—
Indefinite	67	—
	$ 5,714	$ 1,081

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. A recognition threshold and measurement attribute are utilized for financial statement recognition and measurement of tax positions taken or expected to be taken on the tax return. As of December 31, 2019 and 2018, FirstEnergy's total unrecognized income tax benefits were approximately $164 million and $158 million, respectively. The change in unrecognized income tax benefits from the prior year is primarily attributable to increases of approximately $14 million for the reserve for estimated nondeductible interest under Section 163(j) and $6 million for reserves on the estimated worthless stock deduction (see Note 3, Discontinued Operations, for further discussion). These increases were partially offset by a remeasurement of the 2018 reserve related to the estimated nondeductible interest under Section 163(j) of approximately $11 million, as well as a $3 million decrease due to the lapse in statute in certain state taxing jurisdictions. If ultimately recognized in future years, approximately $151 million of unrecognized income tax benefits would impact the effective tax rate.

As of December 31, 2019, it is reasonably possible that approximately $59 million of unrecognized tax benefits may be resolved during 2020 as a result of settlements with taxing authorities or the statute of limitations expiring, of which $57 million would affect FirstEnergy's effective tax rate.

The following table summarizes the changes in unrecognized tax positions for the years ended December 31, 2019, 2018 and 2017:

	(In millions)
Balance, January 1, 2017	$ 84
Current year increases	2
Decrease for lapse in statute	(6)
Balance, December 31, 2017	$ 80
Current year increases	125
Prior year decreases	(45)
Decrease for lapse in statute	(2)
Balance, December 31, 2018	$ 158
Current year increases	22
Prior years decreases	(12)
Decrease for lapse in statute	(4)
Balance, December 31, 2019	$ 164

FirstEnergy recognizes interest expense or income and penalties related to uncertain tax positions in income taxes 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's recognition of net interest associated with unrecognized tax benefits in 2019, 2018 and 2017, was not material. For the years ended December 31, 2019 and 2018, the cumulative net interest payable recorded by FirstEnergy was not material.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state taxing authorities. In June 2019, the IRS completed its examination of FirstEnergy's 2017 federal income tax return and issued a Full Acceptance Letter with no changes or adjustments to FirstEnergy's taxable income. Tax year 2018 is currently under review by the IRS. FirstEnergy's tax returns for some state jurisdictions are open from 2009-2018.

General Taxes

General tax expense for the years ended December 31, 2019, 2018 and 2017, recognized in continuing operations is summarized as follows:

	For the Years Ended December 31,		
	2019	**2018**	**2017**
		(In millions)	
KWH excise	$ 191	$ 198	$ 188
State gross receipts	185	192	184
Real and personal property	504	478	452
Social security and unemployment	100	103	96
Other	28	22	20
Total general taxes	$ 1,008	$ 993	$ 940

8. LEASES

FirstEnergy primarily leases vehicles as well as building space, office equipment, and other property and equipment under cancelable and non-cancelable leases. FirstEnergy does not have any material leases in which it is the lessor.

FirstEnergy adopted ASU 2016-02, *"Leases (Topic 842)"* on January 1, 2019, and elected a number of transitional practical expedients provided within the standard. These included a "package of three" expedients that must be taken together and allowed 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. In addition, FirstEnergy elected the option to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Adoption of the standard on January 1, 2019, did not result in a material cumulative effect adjustment upon adoption. FirstEnergy did not evaluate land easements under the new guidance as they were not previously accounted for as leases. FirstEnergy also elected not to separate lease components from non-lease components as non-lease components were not material.

Leases with an initial term of 12 months or less are recognized as lease expense on a straight-line basis over the lease term and not recorded on the balance sheet. Most leases include one or more options to renew, with renewal terms that can extend the lease

term from 1 to 40 years, and certain leases include options to terminate. The exercise of lease renewal options is at FirstEnergy's sole discretion. Renewal options are included within the lease liability if they are reasonably certain based on various factors relative to the contract. Certain leases also include options to purchase the leased property. The depreciable life of leased assets and leasehold improvements are limited by the expected lease term, unless there is a transfer of title or purchase option reasonably certain of exercise. FirstEnergy's lease agreements do not contain any material restrictive covenants.

For vehicles leased under master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. As of December 31, 2019, the maximum potential loss for these lease agreements at the end of the lease term is approximately $15 million.

Finance leases for assets used in regulated operations are recognized in FirstEnergy's Consolidated Statements of Income (Loss) such that amortization of the right-of-use asset and interest on lease liabilities equals the expense allowed for ratemaking purposes. Finance leases for regulated and non-regulated operations are accounted for as if the assets were owned and financed, with associated expense recognized in Interest expense and Provision for depreciation on FirstEnergy's Consolidated Statements of Income (Loss), while all operating lease expenses are recognized in Other operating expense. The components of lease expense were as follows:

	For the Year Ended December 31, 2019			
(In millions)	**Vehicles**	**Buildings**	**Other**	**Total**
Operating lease costs [1]	$ 28	$ 9	$ 12	$ 49
Finance lease costs:				
Amortization of right-of-use assets	15	1	1	17
Interest on lease liabilities	3	3	—	6
Total finance lease cost	18	4	1	23
Total lease cost	$ 46	$ 13	$ 13	$ 72

[1] Includes $13 million of short-term lease costs.

Supplemental cash flow information related to leases was as follows:

(In millions)	**For the Year Ended December 31, 2019**
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 29
Operating cash flows from finance leases	5
Finance cash flows from finance leases	25
Right-of-use assets obtained in exchange for lease obligations:	
Operating leases	$ 83
Finance leases	3

Lease terms and discount rates were as follows:

	As of December 31, 2019
Weighted-average remaining lease terms (years)	
Operating leases	9.42
Finance leases	4.62
Weighted-average discount rate [1]	
Operating leases	4.51%
Finance leases	10.45%

[1] When an implicit rate is not readily determinable, an incremental borrowing rate is utilized, determining the present value of lease payments. The rate is determined based on expected term and information available at the commencement date.

Supplemental balance sheet information related to leases was as follows:

(In millions)	Financial Statement Line Item	As of December 31, 2019
Assets		
Operating lease assets, net of accumulated amortization of $23 million	Deferred charges and other assets	$ 231
Finance lease assets, net of accumulated amortization of $90 million	Property, plant and equipment	73
Total leased assets		$ 304
Liabilities		
Current:		
Operating	Other current liabilities	$ 32
Finance	Currently payable long-term debt	15
Noncurrent:		
Operating	Other noncurrent liabilities	241
Finance	Long-term debt and other long-term obligations	45
Total leased liabilities		$ 333

Maturities of lease liabilities as of December 31, 2019, were as follows:

(In millions)	Operating Leases	Finance Leases	Total
2020	$ 40	$ 20	$ 60
2021	40	17	57
2022	40	15	55
2023	36	8	44
2024	29	4	33
Thereafter	154	16	170
Total lease payments [(1)]	339	80	419
Less imputed interest	(66)	(20)	(86)
Total net present value	$ 273	$ 60	$ 333

[(1)] Operating lease payments for certain leases are offset by sublease receipts of $13 million over 13 years.

As of December 31, 2019, additional operating leases agreements, primarily for vehicles, that have not yet commenced are $13 million. These leases are expected to commence within the next 18 months with lease terms of 3 to 10 years.

ASC 840, "Leases" Disclosures

The future minimum capital lease payments as of December 31, 2018, as reported in the 2018 Annual Report on Form 10-K for the year ended December 31, 2018 under ASC 840 "*Leases*" are as follows:

Capital Leases	***(In millions)***
2019	$ 24
2020	19
2021	16
2022	13
2023	8
Years thereafter	16
Total minimum lease payments	96
Interest portion	(23)
Present value of net minimum lease payments	73
Less current portion	18
Noncurrent portion	$ 55

The future minimum operating lease payments as of December 31, 2018, as reported in the 2018 Annual Report on Form 10-K for the year ended December 31, 2018 under ASC 840 "*Leases*" are as follows:

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

Operating lease expense under ASC 840 "*Leases*" for the years ended December 31, 2018 and 2017 were $48 million and $53 million, respectively.

9. INTANGIBLE ASSETS

As of December 31, 2019, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheets include the following:

	Intangible Assets			**Amortization Expense**						
				Actual	**Estimated**					
(In millions)	**Gross**	**Accumulated Amortization**	**Net**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**
NUG contracts[1]	$ 124	$ 46	$ 78	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 53
Coal contracts[2]	102	100	2	3	2	—	—	—	—	—
	$ 226	$ 146	$ 80	$ 8	$ 7	$ 5	$ 5	$ 5	$ 5	$ 53

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

10. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

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

Level 1 - Quoted prices for identical instruments in active market

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

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

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

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast are used to measure fair value.

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

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

For investments reported at NAV where there is no readily determinable fair value, a practical expedient is available that allows the NAV to approximate fair value. Investments that use NAV as a practical expedient are excluded from the requirement to be categorized within the fair value hierarchy tables. Instead, these investments are reported outside of the fair value hierarchy tables to assist in the reconciliation of investment balances reported in the tables to the balance sheet. FirstEnergy has elected the NAV practical expedient for investments in private equity funds, insurance-linked securities, hedge funds (absolute return) and real estate funds held within the pension plan. See Note 5, "Pension And Other Postemployment Benefits" for the pension financial assets accounted for at fair value by level within the fair value hierarchy.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2019, from those used as of December 31, 2018. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

	December 31, 2019				December 31, 2018			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$ —	$ 135	$ —	$ 135	$ —	$ 405	$ —	$ 405
Derivative assets FTRs[1]	—	—	4	4	—	—	10	10
Equity securities[2]	2	—	—	2	339	—	—	339
Foreign government debt securities	—	—	—	—	—	13	—	13
U.S. government debt securities	—	—	—	—	—	20	—	20
U.S. state debt securities	—	271	—	271	—	250	—	250
Other[3]	627	789	—	1,416	367	34	—	401
Total assets	$ 629	$ 1,195	$ 4	$ 1,828	$ 706	$ 722	$ 10	$ 1,438
Liabilities								
Derivative liabilities FTRs[1]	$ —	$ —	$ (1)	$ (1)	$ —	$ —	$ (1)	$ (1)
Derivative liabilities NUG contracts[1]	—	—	(16)	(16)	—	—	(44)	(44)
Total liabilities	$ —	$ —	$ (17)	$ (17)	$ —	$ —	$ (45)	$ (45)
Net assets (liabilities)[4]	$ 629	$ 1,195	$ (13)	$ 1,811	$ 706	$ 722	$ (35)	$ 1,393

(1) Contracts are subject to regulatory accounting treatment and changes in market values do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Low Volatility High Dividend Index, S&P 500 Index, MSCI World Index and MSCI AC World IMI Index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $(16) million and $4 million as of December 31, 2019, and December 31, 2018, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the years ended December 31, 2019 and December 31, 2018:

	NUG Contracts[1]			FTRs[1]		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2018 Balance	$ —	$ (79)	$ (79)	$ 3	$ —	$ 3
Unrealized gain (loss)	—	2	2	8	1	9
Purchases	—	—	—	5	(5)	—
Settlements	—	33	33	(6)	3	(3)
December 31, 2018 Balance	$ —	$ (44)	$ (44)	$ 10	$ (1)	$ 9
Unrealized gain (loss)	—	(11)	(11)	(1)	—	(1)
Purchases	—	—	—	6	(4)	2
Settlements	—	39	39	(11)	4	(7)
December 31, 2019 Balance	$ —	$ (16)	$ (16)	$ 4	$ (1)	$ 3

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

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the year ended December 31, 2019:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 3	Model	RTO auction clearing prices	$0.70 to $3.40	$1.30	Dollars/MWH
NUG Contracts	$ (16)	Model	Generation	400 to 330,000	115,000	MWH
			Regional electricity prices	$25.30 to $35.20	$26.30	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include equity securities, AFS debt securities and other investments. FirstEnergy has no debt securities held for trading purposes.

Generally, unrealized gains and losses on equity securities are recognized in income whereas unrealized gains and losses on AFS debt securities are recognized in AOCI. However, the NDTs of JCP&L, ME and PN are subject to regulatory accounting with all gains and losses on equity and AFS debt securities offset against regulatory assets.

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

Nuclear Decommissioning and Nuclear Fuel Disposal Trusts

JCP&L, ME and PN hold debt and equity securities within their respective NDT and nuclear fuel disposal trusts. The debt securities are classified as AFS securities, recognized at fair market value. As further discussed in Note 15, "Commitments, Guarantees and Contingencies", assets and liabilities held for sale on the FirstEnergy Consolidated Balance Sheets associated with the TMI-2 transaction consist of an ARO of $691 million , NDTs of $882 million, as well as property, plant and equipment with a net book value of zero, which are included in the regulated distribution segment.

The following table summarizes the amortized cost basis, unrealized gains, unrealized losses and fair values of investments held in NDT and nuclear fuel disposal trusts as of December 31, 2019 and December 31, 2018:

	December 31, 2019[(1)]				December 31, 2018[(2)]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value[(3)]	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$ 403	$ 9	$ (11)	$ 401	$ 714	$ 2	$ (28)	$ 688
Equity securities	$ —	$ —	$ —	$ —	$ 339	$ 15	$ (16)	$ 338

(1) Excludes short-term cash investments of $751 million, of which $747 million is classified as held for sale.
(2) Excludes short-term cash investments of $20 million.
(3) Includes $135 million classified as held for sale.

Proceeds from the sale of investments in equity and AFS debt securities, realized gains and losses on those sales and interest and dividend income for the years ended December 31, 2019, 2018 and 2017, were as follows:

	For the Years Ended December 31,		
	2019	2018[(1)]	2017[(1)]
	(In millions)		
Sale Proceeds	$ 1,637	$ 800	$ 1,230
Realized Gains	98	41	74
Realized Losses	(31)	(48)	(58)
Interest and Dividend Income	38	41	39

(1) Excludes amounts classified as discontinued operations.

Other Investments

Other investments include employee benefit trusts, which are primarily invested in corporate-owned life insurance policies, and equity method investments. Other investments were $299 million and $253 million as of December 31, 2019 and December 31, 2018, respectively, and are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt, which excludes finance lease obligations and net unamortized debt issuance costs, premiums and discounts as of December 31, 2019 and 2018:

	As of December 31,	
	2019	2018
	(In millions)	
Carrying Value [(1)]	$ 20,074	$ 18,315
Fair Value	22,928	19,266

(1) The carrying value as of December 31, 2019, includes $2.3 billion of debt issuances and $789 million of redemptions that occurred during 2019.

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2019 and December 31, 2018.

11. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2019, FirstEnergy had an accumulated deficit of $4.0 billion. Dividends declared in 2019 and 2018 were $1.53 and $1.82 per share, respectively. Dividends of $0.38 per share and $0.36 per share were paid in the first, second, third and fourth quarters in 2019 and 2018, respectively. On November 8, 2019, the Board of Directors declared a quarterly dividend of $0.39 per share to be paid from OPIC in the first quarter of 2020. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity-to-total-capitalization ratio remains above 35%. In addition, AGC has authorization from FERC to pay cash dividends to its parent from paid-in capital accounts, as long as its FERC-defined equity-to-total-capitalization ratio remains above 45%. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy’s subsidiaries’ abilities to pay cash dividends to FE as of December 31, 2019.

Common Stock Issuance

Additionally, FE issued approximately 3 million shares of common stock in 2019, 3.2 million shares of common stock in 2018 and 3.0 million shares of common stock in 2017 to registered shareholders and its directors and the employees of its subsidiaries under its Stock Investment Plan and certain share-based benefit plans.

On January 22, 2018, FE entered into a Common Stock Purchase Agreement for the private placement of 30,120,482 shares of FE’s common stock, par value $0.10 per share, representing an investment of $850 million ($3 million of common shares and $847 million of OPIC). Please see below for information on preferred stock converted into shares of common stock during 2018 and 2019.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2019, as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FE	5,000,000	$ 100		
OE	6,000,000	$ 100	8,000,000	no par
OE	8,000,000	$ 25		
Penn	1,200,000	$ 100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$ 100	5,000,000	$ 25
TE	12,000,000	$ 25		
JCP&L	15,600,000	no par		
ME	10,000,000	no par		
PN	11,435,000	no par		
MP	940,000	$ 100		
PE	10,000,000	$ 0.01		
WP	32,000,000	no par		

As of December 31, 2019, there were no preferred stock outstanding. As of December 31, 2019 and 2018, there were no preference stock outstanding.

Preferred Stock Issuance

FE entered into a Preferred Stock Purchase Agreement for the private placement of 1,616,000 shares of mandatorily convertible preferred stock, designated as the Series A Convertible Preferred Stock, par value $100 per share, representing an investment of nearly $1.62 billion ($162 million of mandatorily convertible preferred stock and $1.46 billion of OPIC).

The preferred stock participated in dividends on the common stock on an as-converted basis based on the number of shares of common stock a holder of preferred stock would have received if its shares of preferred stock were converted on the dividend record date at the conversion price in effect at that time. Such dividends were paid at the same time that the dividends on common stock were paid.

During 2018, 911,411 shares of preferred stock were converted into 33,238,910 shares of common stock at the option of the preferred stockholders. Also, at the option of the preferred stockholders, 494,767 shares of preferred stock were converted into 18,044,018 shares of common stock in January 2019. On July 22, 2019, 28,302 shares of preferred stock automatically converted into 1,032,165 shares of common stock, and 181,520 shares of preferred stock remained unconverted as the holder reached the 4.9% cap as outlined in the terms of the preferred stock. The remaining 181,520 preferred stock shares were converted on August 1, 2019, into 6,619,985 shares of common stock. As of December 31, 2019, 1,616,000 shares of preferred stock were converted into 58,935,078 shares of common stock and as a result, there are no preferred shares outstanding.

The preferred stock included an embedded conversion option at a price that was below the fair value of the common stock on the commitment date. This beneficial conversion feature, which was approximately $296 million, represents the difference between the fair value per share of the common stock and the conversion price, multiplied by the number of common shares issuable upon conversion. The beneficial conversion feature was amortized as a deemed dividend over the period from the issue date to the first allowable conversion date (July 22, 2018) as a charge to OPIC, since FE is in an accumulated deficit position with no retained earnings to declare a dividend. As noted above, for EPS reporting purposes, this beneficial conversion feature was reflected in net income attributable to common stockholders as a deemed dividend. The beneficial conversion feature ($296 million) was fully amortized during the third quarter of 2018.

Each share of preferred stock was convertible at the holder’s option into a number of shares of common stock equal to the $1,000 liquidation preference, divided by the conversion price then in effect ($27.42 per share). The conversion price was subject to anti-dilution adjustments and adjustments for subdivisions and combinations of the common stock, as well as dividends on the common stock paid in common stock and for certain equity issuances below the conversion price then in effect.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and finance lease obligations for FirstEnergy as of December 31, 2019 and 2018:

	As of December 31, 2019		As of December 31,	
(Dollar amounts in millions)	**Maturity Date**	**Interest Rate**	**2019**	**2018**
FMBs and secured notes - fixed rate	2020-2059	1.726% - 8.250%	$ 4,741	$ 4,355
Unsecured notes - fixed rate	2020-2049	2.850% - 7.375%	14,575	13,450
Unsecured notes - variable rate	2021	2.480%	750	500
Finance lease obligations			60	73
Unamortized debt discounts			(33)	(39)
Unamortized debt issuance costs			(103)	(95)
Unamortized fair value adjustments			8	10
Currently payable long-term debt			(380)	(503)
Total long-term debt and other long-term obligations			$ 19,618	$ 17,751

On January 10, 2019, ME issued $500 million of 4.30% senior notes due 2029. Proceeds from the issuance of senior notes were primarily used to refinance existing indebtedness, including ME’s $300 million of 7.70% senior notes due 2019, and borrowings outstanding under the FE regulated utility money pool and the FE Facility, 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 primarily used to refinance existing indebtedness, including amounts outstanding under the FE regulated utility money pool incurred in connection with the repayment at maturity of JCP&L’s $300 million of 7.35% senior notes due 2019 and the funding of storm recovery and restoration costs and expenses, to fund capital expenditures and working capital requirements and for other general corporate purposes.

On March 28, 2019, FET issued $500 million of 4.55% senior notes due 2049. Proceeds from the issuance of the senior notes were used primarily to support FET’s capital structure, to repay short-term borrowings outstanding under the FE unregulated money pool, to finance capital improvements, and for other general corporate purposes, including funding working capital needs and day-to-day operations.

On April 15, 2019, ATSI issued $100 million of 4.38% senior notes due 2031. Proceeds from the issuance of the senior notes were used primarily to repay short-term borrowings, to fund capital expenditures and working capital needs, and for other general corporate purposes.

On May 21, 2019, WP issued $100 million of 4.22% FMBs due 2059. Proceeds from the issuance of the FMBs were or are, as the case may be, used to refinance existing indebtedness, to fund capital expenditures, and for other general corporate purposes.

On June 3, 2019, PN issued $300 million of 3.60% senior notes due 2029. Proceeds from the issuance of the senior notes were used to refinance existing indebtedness, including amounts outstanding under the FE regulated companies’ money pool incurred in connection with the repayment at maturity of PN’s $125 million of 6.63% senior notes due 2019, to fund capital expenditures, and for other general corporate purposes.

On June 5, 2019, AGC issued $50 million of 4.47% senior unsecured notes due 2029. Proceeds from the issuance of the senior notes were used to improve liquidity, re-establish the debt component within its capital structure following the recent redemption of all of its existing long-term debt, and satisfy working capital requirements and other general corporate purposes.

On August 15, 2019, WP issued $150 million of 4.22% FMBs due 2059. Proceeds were used to refinance existing indebtedness, fund capital expenditures and for other general corporate purposes.

On November 14, 2019, MP issued $155 million of 3.23% FMBs due 2029 and $45 million of 3.93% FMBs due 2049. Proceeds were used to refinance existing debt, to fund capital expenditures, and for other general corporate purposes.

See Note 8, "Leases," for additional information related to finance leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. Creditors of FirstEnergy, other than the limited liability company SPEs, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2019 and 2018, $333 million and $358 million of environmental control bonds were outstanding, respectively.

Transition Bonds

In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding II and are collateralized by its equity and assets, which consist primarily of bondable transition property. As of December 31, 2019 and 2018, $25 million and $41 million of the transition bonds were outstanding, respectively.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. The SPEs are considered VIEs and each one is consolidated into its applicable utility. As of December 31, 2019 and 2018, $268 million and $292 million of the phase-in recovery bonds were outstanding, respectively.

Other Long-term Debt

The Ohio Companies and Penn each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2019, the sinking fund requirement for all FMBs issued under the various mortgage indentures was zero.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding finance leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2019. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

Year	***(In millions)***
2020	$ 364
2021	$ 882
2022	$ 1,142
2023	$ 1,194
2024	$ 1,246

Certain PCRBs allow bondholders to tender their PCRBs for mandatory purchase prior to maturity. As of December 31, 2019, MP has a $73.5 million PCRB classified as long-term debt, which the debt holders may exercise their right to tender in 2021.

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities and term loans. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2019, FirstEnergy remains in compliance with all debt covenant provisions.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries, excluding AE Supply, default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI, TrAIL or MAIT would generally cross-default FE financing arrangements containing these provisions, defaults by AE Supply would generally not cross-default to applicable financing arrangements of FE. Also, defaults by FE would generally not cross-default applicable financing arrangements of any of FE's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FE or the Utilities.

12. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had $1,000 million and $1,250 million of short-term borrowings as of December 31, 2019 and 2018, respectively.

FE and the Utilities and FET and certain of its subsidiaries participate in two separate five-year syndicated revolving credit facilities providing for aggregate commitments of $3.5 billion, which are available until December 6, 2022. Under the FE credit 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 FET credit 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 FE's transmission subsidiaries. As of December 31, 2019, available liquidity under the FE and FET revolving credit facilities was $2,496 million (reflecting $4 million of LOCs issued under various terms) and $1,000 million respectively.

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

Borrowings under the credit 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 each of the credit 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 credit facilities contains financial covenants requiring each borrower to maintain a consolidated debt-to-total-capitalization ratio (as defined under each of the credit facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

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. 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, 2019, the borrowers were in compliance with the applicable debt-to-total-capitalization ratio 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 revolving credit facility described above, including a consolidated debt-to-total-capitalization ratio. Effective September 11, 2019, the two credit agreements noted above were amended to change the amounts available under the existing facilities from $1.25 billion and $500 million to $1 billion and $750 million, respectively, and extend the maturity dates until September 9, 2020, and September 11, 2021, respectively.

The borrowing of $1.75 billion under the 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 2019 was 2.27% per annum for the regulated companies' money pool and 2.74% per annum for the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2019 and 2018, were 2.88% and 3.07%, respectively.

13. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost, primarily for the decommissioning of the TMI-2 nuclear generating facility and environmental remediation, including reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks and wastewater treatment lagoons. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The following table summarizes the changes to the ARO balances during 2019 and 2018:

ARO Reconciliation		***(In millions)***
Balance, January 1, 2018	$	570
Changes in timing and amount of estimated cash flows		203
Liabilities settled		(1)
Accretion		40
Balance, December 31, 2018	$	812
Liabilities settled		(2)
Accretion		46
Balance, December 31, 2019 [(1)]	$	856

(1) Includes $691 million related to TMI-2 classified as held for sale. See Note 15, "Commitments, Guarantees and Contingencies," for further information.

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. On November 4, 2019, the EPA issued a proposed rule accelerating the date that certain CCR impoundments must cease accepting waste and initiate closure to August 31, 2020. The proposed rule, which includes a 60-day comment period, provides exceptions, which could allow extensions to closure dates.

During the fourth quarter of 2018, based on studies completed by a third-party to reassess the estimated costs and timing to decommission TMI-2, JCP&L, ME and PN increased their ARO by a total of approximately $172 million, with a regulatory offset. The increase in the ARO resulted primarily from accelerated timing of the estimated cash flows associated with decommissioning.

14. REGULATORY MATTERS

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in New Jersey by the NJBPU, in Ohio by the PUCO, 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 base distribution rate orders in effect for the Utilities as of December 31, 2019:

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)	March 2019	47% / 53%	9.65%
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 March 23, 2019. 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 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.

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. The MDPSC approved PE’s compliance filing, which implements the pilot program, with minor modifications, on July 3, 2019.

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 reflected $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On March 22, 2019, the MDPSC issued a final order that approved a rate increase of $6.2 million, approved three of the four EDIS programs for four years, directed PE to file a new depreciation study within 18 months, and ordered the filing of a new base rate case in four years to correspond to the ending of the approved EDIS programs.

NEW JERSEY

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

On April 18, 2019, pursuant to the May 2018 New Jersey enacted legislation establishing a ZEC program to provide ratepayer funded subsidies of New Jersey nuclear energy supply, the NJBPU approved the implementation of a non-bypassable, irrevocable ZEC charge for all New Jersey electric utility customers, including JCP&L's customers. Once collected from customers by JCP&L, these funds will be remitted to eligible nuclear energy generators.

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 ratepayers; 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. On May 17, 2019, the Rate Counsel filed an appeal with the Appellate Division of the Superior Court of New Jersey. JCP&L is contesting this appeal but is unable to predict the outcome of this matter.

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 April 23, 2019, JCP&L filed a Stipulation of Settlement with the NJBPU on behalf of the JCP&L, Rate Counsel, NJBPU Staff and New Jersey Large Energy Users Coalition, which provides that JCP&L will invest up to approximately $97 million in capital investments beginning on June 1, 2019 through December 31, 2020. JCP&L shall seek recovery of the capital investment through an accelerated cost recovery mechanism, provided for in the rules, that includes a revenue adjustment calculation and a process for two rate adjustments. On May 8, 2019, the NJBPU issued an order approving the Stipulation of Settlement without modifications. Pursuant to the Stipulation, JCP&L filed a petition on September 16, 2019, to seek approval of rate adjustments to provide for cost recovery established with JCP&L Reliability Plus.

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. On April 23, 2019, JCP&L filed a Stipulation of Settlement on behalf of the Rate Counsel, NJBPU Staff, and the New Jersey Large Energy Users Coalition with the NJBPU. The terms of the Stipulation of Settlement provide that between January 1, 2018 and March 31, 2018, JCP&L's refund obligation is estimated to be approximately $7 million, which was refunded to customers in 2019. The Stipulation of Settlement also provides for a base rate reduction of $28.6 million, which was reflected in rates on April 1, 2018, and a Rider Tax Act Adjustment for certain items over a five-year period. On May 8, 2019, the NJBPU issued an order approving the Stipulation of Settlement without modification.

JCP&L expects to file a distribution base rate case in New Jersey in February 2020, which will seek to recover certain costs associated with providing safe and reliable electric service to JCP&L customers, along with recovery of previously incurred storm costs.

OHIO

The Ohio Companies operate under base distribution rates approved by the PUCO effective in 2009. The Ohio Companies' residential and commercial base distribution revenues are decoupled, through a mechanism that took effect on February 1, 2020, to the base distribution revenue and lost distribution revenue associated with energy efficiency and peak demand reduction programs recovered as of the twelve-month period ending on December 31, 2018. The Ohio Companies currently operate under ESP IV effective June 1, 2016, and continuing through May 31, 2024, that continues the supply of power to non-shopping customers at a market-based price set through an auction process. ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $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. In addition, ESP IV includes: (1) continuation of a base distribution rate freeze through May 31, 2024; (2) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; and (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.

ESP IV further provided for the Ohio Companies to collect through Rider DMR $132.5 million annually for three years beginning in 2017, grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. Revenues from Rider DMR are excluded from the significantly excessive earnings test. On appeal, the SCOH, on June 19, 2019, reversed the PUCO's determination that Rider DMR is lawful, and remanded the matter to the PUCO with instructions to remove Rider DMR from ESP IV. On August 20, 2019, the SCOH denied the Ohio Companies' motion for reconsideration. The PUCO entered an Order directing the Ohio Companies to cease further collection through Rider DMR, credit back to customers a refund of Rider DMR funds collected since July 2, 2019, and remove Rider DMR from ESP IV. On October 1, 2019, the Ohio Companies implemented PUCO approved tariffs to refund approximately $28 million to customers, including Rider DMR revenues billed from July 2, 2019 through August 31, 2019.

On July 15, 2019, OCC filed a Notice of Appeal with the SCOH, challenging the PUCO's exclusion of Rider DMR revenues from the determination of the existence of significantly excessive earnings under ESP IV for calendar year 2017 and claiming a $42 million refund is due to OE customers. The Ohio Companies are contesting this appeal but are unable to predict the outcome of this matter.

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 includes a portfolio of energy efficiency programs targeted to a variety of customer segments. The Ohio Companies anticipate the cost of the plan will be approximately $268 million over the life of the plan 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 plan 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 October 15, 2019, the SCOH reversed the PUCO's decision to impose the 4% cost-recovery cap and remanded the matter to the PUCO for approval of the portfolio plans without the cost-recovery cap.

On July 23, 2019, Ohio enacted legislation establishing support for nuclear energy supply in Ohio. In addition to the provisions supporting nuclear energy, the legislation included a provision implementing a decoupling mechanism for Ohio electric utilities. The legislation also is ending current energy efficiency program mandates on December 31, 2020, provided statewide energy efficiency mandates are achieved as determined by the PUCO. On October 23, 2019, the PUCO solicited comments on whether the PUCO should terminate the energy efficiency programs once the statewide energy efficiency mandates are achieved. Opponents to the legislation sought to submit it to a statewide referendum, and stay its effect unless and until approved by a majority of Ohio voters. Petitioners filed a lawsuit in the U.S. District Court for the Southern District of Ohio seeking additional time to gather signatures in support of a referendum. Petitioners failed to file the necessary number of petition signatures, and the legislation took effect on October 22, 2019. On October 23, 2019, the U.S. District Court denied petitioners' request for more time, and certified questions of state law to the SCOH to answer. Petitioners appealed the U.S. District Court's decision to the U.S. Court of Appeals for the Sixth Circuit. The Petitioners ended their challenge to the legislation voluntarily at the end of January 2020 causing the dismissal of the appeal, the lawsuit before the U.S District Court, and the proceedings before the SCOH.

On November 21, 2019, the Ohio Companies applied to the PUCO for approval of a decoupling mechanism, which would set residential and commercial base distribution related revenues at the levels collected in 2018. As such, those base distribution revenues would no longer be based on electric consumption, which allows continued support of energy efficiency initiatives while also providing revenue certainty to the Ohio Companies. On January 15, 2020, the PUCO approved the Ohio Companies' decoupling application, and the decoupling mechanism took effect on February 1, 2020.

In February 2016, the Ohio Companies filed a Grid Modernization Business Plan for PUCO consideration and approval, as required by the terms of ESP IV. On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan, a portfolio 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. Also, on January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act on Ohio utilities' rates and determine the appropriate course of action to pass benefits on to customers. 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 to flow back to customers. 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 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 had 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. On July 17, 2019, the PUCO approved the settlement agreement with no material modifications. On September 11, 2019, the PUCO denied the application for rehearing of environmental advocates who were not parties to the settlement.

The Ohio Companies' Rider NMB is designed to recover NMB transmission-related costs imposed on or charged to the Ohio Companies by FERC or PJM. On December 14, 2018, the Ohio Companies filed an application for a review of their 2019 Rider NMB, including recovery of future Legacy RTEP costs and previously absorbed Legacy RTEP costs, net of refunds received from PJM. On February 27, 2018, the PUCO issued an order directing the Ohio Companies to file revised final tariffs recovering Legacy RTEP costs incurred since May 31, 2018, but excluding recovery of approximately $95 million in Legacy RTEP costs incurred prior to May 31, 2018, net of refunds received from PJM. The PUCO solicited comments on whether the Ohio Companies should be permitted to recover the Legacy RTEP charges incurred prior to May 31, 2018. On October 9, 2019, the PUCO approved the recovery of the $95 million of previously excluded Legacy RTEP charges.

PENNSYLVANIA

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. These rates were adjusted for the net impact of the Tax Act, effective March 15, 2018. The net impact of the Tax Act for the period January 1, 2018 through March 14, 2018 must also be separately tracked for treatment in a future rate proceeding. The Pennsylvania Companies operate under DSPs for the June 1, 2019 through May 31, 2023 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 2019-2023 DSPs, 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, modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW, customer assistance program shopping limitations, and script modifications related to the Pennsylvania Companies' customer referral programs.

Pursuant to Pennsylvania 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. 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. Following a periodic review of the LTIIPs in 2018 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 May 23, 2019, the PPUC approved the Pennsylvania Companies' Modified LTIIPs that revised LTIIP spending in 2019 of approximately $45 million by ME, $25 million by PN, $26 million by Penn and $51 million by WP, and terminating at the end of 2019. On August 30, 2019, the Pennsylvania Companies filed Petitions for approval of proposed LTIIPs for the five-year period beginning January 1, 2020 and ending December 31, 2024 for a total capital investment of approximately $572 million for certain infrastructure improvement initiatives. On January 16, 2020, the PPUC approved the LTIIPs without modification, as well as directed the Pennsylvania Companies to submit corrective action plans by March 16, 2020, which outline how they will reduce their pole replacement backlogs over a five-year period to a rolling two-year backlog.

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. The parties to the DSIC proceeding submitted a Joint Settlement that resolved the issues that were pending from the order issued on June 9, 2016, and 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. The Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision, and the Pennsylvania Companies contested the appeal. The Commonwealth Court reversed the PPUC's decision of April 19, 2018 and remanded the matter to the PPUC to require the Pennsylvania Companies to revise their tariffs and DSIC calculations to include ADIT and state income taxes. The Commonwealth Court denied Applications for Reargument in the Court's July 11, 2019 Opinion and Order filed by the PPUC and the Pennsylvania Companies. On October 7, 2019, the PPUC and the Pennsylvania Companies filed separate Petitions for Allowance of Appeal of the Commonwealth Court's Opinion and Order to the Pennsylvania Supreme Court.

On August 30, 2019, Penn filed a Petition seeking approval of a waiver of the statutory DSIC cap of 5% of distribution rate revenue and approval to increase the maximum allowable DSIC to 11.81% of distribution rate revenue for the five-year period of its proposed LTIIP. The Pennsylvania Office of Small Business Advocate, the PPUC's Bureau of Investigation, and the Pennsylvania OCA opposed Penn's Petition. On January 17, 2020, the parties filed a petition seeking approval of settlement that provides for a temporary increase in the recoverability cap from 5% to 7.5%, which will expire on the earlier of the effective date of new base rates following Penn's next base rate case or the expiration of its LTIIP II program. The settlement is subject to PPUC approval.

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.

On August 21, 2019, MP and PE filed with the WVPSC their annual ENEC case requesting a decrease in ENEC rates of $6.1 million beginning January 1, 2020, representing a 0.4% decrease in rates versus those in effect on August 21, 2019. On October 11, 2019, MP and PE filed a supplement requesting approval of the termination of the 50 MW PPA with Morgantown Energy Associates, a NUG entity. A settlement between MP, PE, and the majority of the intervenors fully resolving the ENEC case, which maintains 2019 ENEC rates into 2020, and supports the termination of the Morgantown Energy Associates PPA, was filed with the WVPSC on October 18, 2019. An order was issued on December 20, 2019, approving the ENEC settlement and termination of the PPA with Morgantown Energy Associates.

On August 21, 2019, MP and PE filed with the WVPSC for a reconciliation of their VMS and a periodic review of its vegetation management program requesting an increase in VMS rates of $7.6 million beginning January 1, 2020. The increase is due to moving from a 5-year maintenance cycle to a 4-year cycle and performing more operation and maintenance work and less capital work on the rights of way. The increase is a 0.5% increase in rates versus those in effect on August 21, 2019. All the parties reached a settlement in the case, and the WVPSC issued its order approving the settlement without change on December 20, 2019.

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 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 as of December 31, 2019:

Company	Rates Effective	Capital Structure	Allowed ROE
ATSI	January 1, 2015	Actual (13 month average)	10.38%
JCP&L	June 1, 2017(1)	Settled(1)(3)	Settled(1)(3)
MP	March 21, 2018(2)	Settled(3)	Settled(3)
PE	March 21, 2018(2)	Settled(3)	Settled(3)
WP	March 21, 2018(2)	Settled(3)	Settled(3)
MAIT	July 1, 2017	Lower of Actual (13 month average) or 60%	10.3%
TrAIL	July 1, 2008	Actual (year-end)	12.7% (TrAIL the Line & Black Oak SVC) 11.7% (All other projects)

(1) Effective on January 1, 2020, JCP&L has implemented a forward-looking formula rate, which has been accepted by FERC, subject to refund, pending further hearing and settlement proceedings.
(2) See FERC Actions on Tax Act below.
(3) FERC-approved settlement agreements did not specify.

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 six 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 material 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.

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.

FERC Actions on Tax Act

On March 15, 2018, FERC initiated proceedings on the question of how to 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 21, 2019, FERC issued a final rule (Order 864). Order 864 requires utilities with transmission formula rates to update their formula rate templates to include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate base; (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. Alternatively, formula rate utilities can demonstrate to FERC that their formula rate template already achieves these outcomes. Utilities with transmission stated rates are required to address these new requirements as part of their next transmission rate case. 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. FirstEnergy’s formula rate transmission utilities will make the required filings on or before the deadlines established in FERC’s order. FirstEnergy’s stated rate transmission utilities will address the requirements as part of their next transmission rate case. JCP&L is addressing the requirements in the course of its pending transmission rate case.

Transmission ROE Methodology

FERC’s methodology for calculating electric transmission utility ROE has been in transition as a result of an April 14, 2017 ruling by the D.C. Circuit that vacated FERC’s then-effective methodology. On October 16, 2018, FERC issued an order in which it proposed a revised ROE methodology. FERC proposed that, for complaint proceedings alleging that an existing ROE is not just and reasonable, FERC will rely on three financial models - discounted cash flow, capital-asset pricing, and expected earnings - to establish a composite zone of reasonableness to identify 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 replacement 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. On March 21, 2019, FERC established NOIs to collect industry and stakeholder comments on the revised ROE methodology that is described in the October 16, 2018 decision, and also whether to make changes to FERC’s existing policies and practices for awarding transmission rates incentives. On November 21, 2019, FERC announced in a complaint proceeding involving MISO utilities that FERC would rely on the discounted cash flow and capital-asset pricing models as the basis for establishing ROE. It is not clear at this time whether FERC’s November ruling will be applied more broadly. Any changes to FERC’s transmission rate ROE and incentive policies would be applied on a prospective basis. FirstEnergy currently is participating through various trade groups in the FERC dockets where the ROE methodology is being reviewed, and on December 23, 2019, JCP&L filed a request for rehearing of FERC’s November decision in the MISO utilities docket.

JCP&L Transmission Formula Rate

On October 30, 2019, JCP&L filed tariff amendments with FERC to convert JCP&L’s existing stated transmission rate to a forward-looking formula transmission rate. JCP&L requested that the tariff amendments become effective January 1, 2020. On December 19, 2019, FERC issued its initial order in the case, allowing JCP&L to transition to a forward-looking formula rate as of January 1, 2020 as requested, subject to refund, pending further hearing and settlement proceedings. JCP&L is engaged in settlement negotiations.

15. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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.

As of December 31, 2019, outstanding guarantees and other assurances aggregated approximately $1.6 billion, consisting of guarantees on behalf of the FES Debtors ($350 million), parental guarantees on behalf of its consolidated subsidiaries' guarantees ($1.0 billion), other guarantees ($114 million) and other assurances ($151 million). FirstEnergy has also committed to provide certain additional guarantees to the FES Debtors for retained environmental liabilities of AE Supply related to the Pleasants Power Station and McElroy's Run CCR disposal facility as part of the settlement agreement in connection with the FES Bankruptcy.

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, 2019, AE Supply has posted no collateral. The Utilities and Transmission Companies have posted no collateral.

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, 2019:

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	—	36	—	36
Surety Bonds (Collateralized Amount)[1]	—	63	257	320
Total Exposure from Contractual Obligations	$ 1	$ 99	$ 257	$ 357

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 $120 million syndicated senior secured term loan facility due November 12, 2024, under which Global Holding's outstanding principal balance is $114 million as of December 31, 2019. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the facility.

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

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. While FirstEnergy's environmental policies and procedures are designed to achieve compliance with applicable environmental laws and regulations, such laws and regulations are subject to periodic review and potential revision by the implementing agencies. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof may materially impact its business, results of operations, cash flows and financial condition.

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. On September 13, 2019, the D.C. Circuit remanded the CSAPR update rule to the EPA citing that the rule did not eliminate upwind states’ significant contributions to downwind states’ air quality attainment requirements within applicable attainment deadlines. 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 materially impact FirstEnergy's operations, cash flows and financial condition.

In February 2019, the EPA announced its final decision to retain without changes the NAAQS for SO_2, specifically retaining the 2010 primary (health-based) 1-hour standard of 75 PPB. As of September 30, 2019, FirstEnergy has no power plants operating in areas designated as non-attainment by the EPA.

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's 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. On September 20, 2019, the EPA denied New York’s CAA Section 126 petition. On October 29, 2019, the State of New York appealed the denial of its petition to the D.C. Circuit. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

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. In 2015, FirstEnergy set a goal of reducing company-wide CO2 emissions by at least 90 percent below 2005 levels by 2045. As of December 31, 2018, FirstEnergy has reduced its CO2 emissions by approximately 62 percent. In September 2016, the U.S. 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's non-binding obligations to limit global warming to 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 CO2 emissions, or litigation alleging damages from GHG emissions, could require material capital and other expenditures or result in changes to its operations.

In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for GHG under the Clean Air Act," 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 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 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. On June 19, 2019, the EPA repealed the CPP and replaced it with the ACE rule that establishes guidelines for states to develop standards of performance to address GHG emissions from existing coal-fired power plants. Depending on the outcomes of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be material.

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 facilities. 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 on September 18, 2017, the EPA postponed certain compliance deadlines for two years. On November 4, 2019, the EPA issued a proposed rule revising the effluent limits for discharges from wet scrubber systems and extending the deadline for compliance to December 31, 2025. The EPA's proposed rule retains the zero discharge standard and 2023 compliance date for ash transport water, but adds some allowances for discharge under certain circumstances. In addition, the EPA allows for less stringent limits for sub-categories of generating units based on capacity utilization, flow volume from the scrubber system, and unit retirement date. 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.

On September 29, 2016, FirstEnergy received a request from the EPA for information pursuant to CWA Section 308(a) for information concerning boron exceedances of effluent limitations established in the NPDES Permit for the former Mitchell Power Station's Mingo landfill, owned by WP. On November 1, 2016, WP provided an initial response that contained information related to a similar boron issue at the former Springdale Power Station's landfill. The EPA requested additional information regarding the Springdale landfill and on November 15, 2016, WP provided a response and intends to fully comply with the Section 308(a) information request. On March 3, 2017, WP proposed to the PA DEP a re-route of its wastewater discharge to eliminate potential boron exceedances at

the Springdale landfill. On January 29, 2018, WP submitted an NPDES permit renewal application to PA DEP proposing to re-route its wastewater discharge to eliminate potential boron exceedances at the Mingo landfill. On February 20, 2018, the DOJ issued a letter and tolling agreement on behalf of EPA alleging violations of the CWA at the Mingo landfill while seeking to enter settlement negotiations in lieu of filing a complaint. On November 4, 2019, the EPA proposed a penalty of nearly $1.3 million to settle alleged past boron exceedances at the Mingo and Springdale landfills. On December 17, 2019, WP responded to the EPA's settlement proposal but is unable to predict the outcome of this matter.

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. On November 4, 2019, the EPA issued a proposed rule accelerating the date that certain CCR impoundments must cease accepting waste and initiate closure to August 31, 2020. The proposed rule, which includes a 60-day comment period, provides exceptions, which could allow extensions to closure dates.

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, 2019, 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 $109 million have been accrued through December 31, 2019. Included in the total are accrued liabilities of approximately $77 million for environmental remediation of former MGP 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, 2019, JCP&L, ME and PN had in total approximately $882 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.

On October 15, 2019, JCP&L, ME, PN and GPUN executed an asset purchase and sale agreement with TMI-2 Solutions, LLC, a subsidiary of Energy*Solutions*, LLC, concerning the transfer and dismantlement of TMI-2. This transfer of TMI-2 to TMI-2 Solutions, LLC will include the transfer of: (i) the ownership and operating NRC licenses for TMI-2; (ii) the external trusts for the decommissioning and environmental remediation of TMI-2; and (iii) related liabilities of approximately $900 million as of December 31, 2019. There can be no assurance that the transfer will receive the required regulatory approvals and, even if approved, whether the conditions to the closing of the transfer will be satisfied. On November 12, 2019, JCP&L filed a Petition with the NJBPU seeking approval of the transfer and sale of JCP&L’s entire 25% interest in TMI-2 to TMI-2 Solutions, LLC. Also on November 12, 2019, JCP&L, ME, PN, GPUN and TMI-2 Solutions, LLC filed an application with the NRC seeking approval to transfer the NRC license for TMI-2 to TMI-2 Solutions, LLC. Both proceedings are ongoing. Assets and liabilities held for sale on the FirstEnergy Consolidated Balance Sheet associated with the transaction consist of asset retirement obligations of $691 million, NDTs of $882 million as well as property, plant and equipment with a net book value of zero, which are included in the regulated distribution segment.

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 14, "Regulatory Matters."

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.

16. TRANSACTIONS WITH AFFILIATED COMPANIES

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

The Utilities and Transmission Companies are parties to an intercompany income tax allocation agreement with FE and its other subsidiaries, including FES and FENOC, that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FE are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see Note 7, "Taxes").

Additionally, the Utilities purchase power from FES to meet a portion of their POLR and default service requirements and provide power to certain facilities. See Note 3, "Discontinued Operations" for additional details.

17. SEGMENT INFORMATION

Regulated Distribution and Regulated Transmission are FirstEnergy's reportable segments.

On March 31, 2018, as discussed in Note 3, “Discontinued Operations,” FirstEnergy deconsolidated FES and FENOC and presented FES, FENOC, BSPC and a portion of AE Supply, representing substantially all of FirstEnergy’s operations that previously comprised the CES reportable operating segment, as discontinued operations in FirstEnergy’s consolidated financial statements resulting from actions taken as part of the strategic review to exit commodity-exposed generation. 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.

The **Regulated Distribution** segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the costs of securing and delivering electric generation from transmission facilities to customers, including the deferral and amortization of certain related costs. Included within the segment are $882 million of assets classified as held for sale associated with the asset purchase and sale agreement with TMI-2 Solutions to transfer TMI-2 to TMI-2 Solutions, LLC. See Note 15, "Commitments, Guarantees and Contingencies" for additional information.

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. Effective January 1, 2020, JPC&L's transmission rates became forward-looking formula rates, subject to refund, pending further hearing and settlement proceedings. 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.

Corporate/Other 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. Reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are shown separately in the following table of Segment Financial Information. As of December 31, 2019, 67 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of Corporate/Other. As of December 31, 2019, Corporate/Other had approximately $7.1 billion of FE holding company debt.

Financial information for each of FirstEnergy's reportable segments is presented in the tables below:

Segment Financial Information

For the Years Ended	Regulated Distribution	Regulated Transmission	Corporate/ Other	Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
December 31, 2019					
External revenues	$ 9,511	$ 1,510	$ 14	$ —	$ 11,035
Internal revenues	187	16	—	(203)	—
Total revenues	9,698	1,526	14	(203)	11,035
Provision for depreciation	863	284	5	68	1,220
Amortization (deferral) of regulatory assets, net	(89)	10	—	—	(79)
Miscellaneous income (expense), net	174	15	80	(26)	243
Interest expense	495	192	372	(26)	1,033
Income taxes (benefits)	271	113	(171)	—	213
Income (loss) from continuing operations	1,076	447	(619)	—	904
Property additions	$ 1,473	$ 1,090	$ 102	$ —	$ 2,665
December 31, 2018					
External revenues	$ 9,900	$ 1,335	$ 26	$ —	$ 11,261
Internal revenues	203	18	8	(229)	—
Total revenues	10,103	1,353	34	(229)	11,261
Provision for depreciation	812	252	3	69	1,136
Amortization (deferral) of regulatory assets, net	(163)	13	—	—	(150)
Miscellaneous income (expense), net	192	14	32	(33)	205
Interest expense	514	167	468	(33)	1,116
Income taxes (benefits)	422	122	(54)	—	490
Income (loss) from continuing operations	1,242	397	(617)	—	1,022
Property additions	$ 1,411	$ 1,104	$ 133	$ 27	$ 2,675
December 31, 2017					
External revenues	$ 9,602	$ 1,307	$ 19	$ —	$ 10,928
Internal revenues	158	17	24	(199)	—
Total revenues	9,760	1,324	43	(199)	10,928
Provision for depreciation	724	224	10	69	1,027
Amortization of regulatory assets, net	292	16	—	—	308
Miscellaneous income (expense), net	57	1	39	(44)	53
Interest expense	535	156	358	(44)	1,005
Income taxes	580	205	930	—	1,715
Income (loss) from continuing operations	916	336	(1,541)	—	(289)
Property additions	$ 1,191	$ 1,030	$ 49	$ 317	$ 2,587
As of December 31, 2019					
Total assets	$ 29,642	$ 11,611	$ 1,015	$ 33	$ 42,301
Total goodwill	$ 5,004	$ 614	$ —	$ —	$ 5,618
As of December 31, 2018					
Total assets	$ 28,690	$ 10,404	$ 944	$ 25	$ 40,063
Total goodwill	$ 5,004	$ 614	$ —	$ —	$ 5,618

As of December 31, 2017

Total assets	$	27,730	$	9,525	$	1,007	$	3,995	$	42,257
Total goodwill	$	5,004	$	614	$	—	$	—	$	5,618

18. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2019 and 2018.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(In millions, except per share amounts)	**2019**				**2018**			
	Dec. 31	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**
Revenues	$ 2,673	$ 2,963	$ 2,516	$ 2,883	$ 2,710	$ 3,064	$ 2,625	$ 2,862
Other operating expense	809	758	606	779	770	739	684	940
Provision for depreciation	310	304	309	297	293	283	283	277
Operating Income	615	681	585	629	512	710	700	580
Pension and OPEB mark-to-market adjustment	(674)	—	—	—	(144)	—	—	—
Income before income taxes	(249)	496	422	448	169	520	409	414
Income taxes	(68)	107	81	93	35	121	101	233
Income from continuing operations	(181)	389	341	355	134	399	308	181
Discontinued operations [1] (Note 3)	70	2	(29)	(35)	4	(857)	(9)	1,188
Net Income (Loss)	(111)	391	312	320	138	(458)	299	1,369
Income allocated to preferred stockholders [2]	—	—	4	5	10	54	165	156
Net income (loss) attributable to common stockholders	(111)	391	308	315	128	(512)	134	1,213
Earnings (loss) per share of common stock-[3]								
Basic - Continuing Operations	(0.33)	0.72	0.63	0.66	0.24	0.68	0.30	0.05
Basic - Discontinued Operations (Note 3)	0.13	0.01	(0.05)	(0.07)	0.01	(1.70)	(0.02)	2.50
Basic - Net Income (Loss) Attributable to Common Stockholders	(0.20)	0.73	0.58	0.59	0.25	(1.02)	0.28	2.55
Diluted - Continuing Operations	(0.33)	0.72	0.63	0.66	0.24	0.68	0.30	0.05
Diluted - Discontinued Operations (Note 3)	0.13	—	(0.05)	(0.07)	0.01	(1.70)	(0.02)	2.49
Diluted - Net Income (Loss) Attributable to Common Stockholders	(0.20)	0.72	0.58	0.59	0.25	(1.02)	0.28	2.54

[1] Net of income taxes

[2] The sum of quarterly income allocated to preferred stockholders may not equal annual income allocated to preferred stockholders as quarter-to-date and year-to-date amounts are calculated independently.

[3] The sum of quarterly earnings per share information may not equal annual earnings per share due to the issuance of shares and conversion of preferred shares throughout the year. See the FirstEnergy Consolidated Statements of Stockholders' Equity and Note 6, "Stock-Based Compensation Plans," for additional information.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The management of FirstEnergy, with the participation of the chief executive officer and chief financial officer, has reviewed and evaluated the effectiveness of their registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934, Rules 13a-15(e) and 15d-15(e), as of the end of the period covered by this report. Based on that evaluation, the chief executive officer and chief financial officer have concluded that FirstEnergy’s disclosure controls and procedures were effective as of the end of the period covered by this report.

Management’s Report on Internal Control over Financial Reporting

See Management’s Report on Internal Control over Financial Reporting under Item 8, "Financial Statements and Supplementary Data". Management is required to assess the effectiveness of FirstEnergy's internal control over financial reporting. Based on that assessment, management concluded that FirstEnergy's internal control over financial reporting was effective as of December 31, 2019.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2019, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FirstEnergy's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 is incorporated herein by reference to FirstEnergy's 2020 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference to FirstEnergy’s 2020 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The Item 403 of Regulation S-K information required by Item 12 is incorporated herein by reference to FirstEnergy's 2020 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

The following table contains information as of December 31, 2019, regarding compensation plans for which shares of FE common stock may be issued.

Plan category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in First Column)
Equity compensation plans approved by security holders	4,316,337 [1]	$ 37.75 [2]	3,947,410 [3]
Equity compensation plans not approved by security holders[4]	—	N/A	—
Total	4,316,337	$ 37.75	3,947,410

[1] Represents shares of common stock that could be issued upon exercise of outstanding options granted under the ICP 2007 and ICP 2015. This number also includes 1,930,139 shares subject to outstanding awards of stock based RSUs granted under the ICP 2015 if paid at target for the three outstanding cycles, as well as 1,930,139 additional shares assuming maximum performance metrics are achieved for the 2017-2019, 2018-2020 and 2019-2021 cycles of stock based RSUs, 2,883 outstanding FE Amended and Restated EDCP related shares to be paid in stock and 372,919 shares related to the FE DCPD that will be paid in stock. Not reflected in the table are 21,282 shares related to the AYE Director's Plan and AYE DCD that will be paid in stock per the election of the recipient.

[2] Only FirstEnergy options were included in the calculation for determining the weighted-average exercise price.

[3] Represents shares available for issuance, assuming maximum performance metrics are achieved (or approximately 5,877,549 available assuming performance at target) for the 2017-2019, 2018-2020, and 2019-2021 cycles of stock-based RSUs, with respect to future awards under the ICP 2015 and future accruals of dividends on awards outstanding under ICP 2015. Additional shares may become available under the ICP 2015 due to cancellations, forfeitures, cash settlements or other similar circumstances with respect to outstanding awards. In addition, nominal amounts of shares may be issued in the future under the AYE Director's Plan and AYE DCD to cover future dividends that may accrue on amounts previously deferred and payable in stock, but new awards are no longer being granted under the Allegheny plans or the ICP 2007.

[4] All equity compensation plans have been approved by security holders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated herein by reference to FirstEnergy’s 2020 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

A summary of the audit and audit-related fees for services rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2019 and 2018, are as follows:

	Audit Fees[1]		Audit-Related Fees	
	2019	2018	2019	2018
	(In thousands)			
FirstEnergy	$ 6,952	$ 7,345	$ —	$ 163

[1] Professional services rendered for the audits of FirstEnergy's annual financial statements and reviews of unaudited financial statements included in FirstEnergy's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters, agreed upon procedures and consents for financings and filings made with the SEC.

Tax Fees and All Other Fees

There were no tax-related fees paid to PricewaterhouseCoopers LLP in 2019 compared to $120,000 in 2018. PricewaterhouseCoopers LLP performed no other services in 2019 or 2018, however, FirstEnergy paid approximately $6,725 and $6,300 in software subscription fees to PricewaterhouseCoopers LLP for 2019 and 2018, respectively.

Additional information required by this item is incorporated herein by reference to FirstEnergy's 2020 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULE

(a) The following documents are filed as a part of this report on Form 10-K:

1. Financial Statements:

Management's Report on Internal Control Over Financial Reporting for FirstEnergy Corp. is listed under Item 8, "Financial Statements and Supplementary Data" herein.

Report of Independent Registered Public Accounting Firm for FirstEnergy Corp. is listed under Item 8, "Financial Statements and Supplementary Data," herein.

The financial statements filed as a part of this report for FirstEnergy Corp. are listed under Item 8, "Financial Statements and Supplementary Data," herein.

2. Financial Statement Schedule:

Report of Independent Registered Public Accounting Firm for FirstEnergy Corp. (including the schedule referenced below) is listed under Item 8, "Financial Statements and Supplementary Data," herein on page:

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Schedule II — Consolidated Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2019, are listed herein on page:

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3. Exhibits

Exhibit Number		
3-1		Amended and Restated Articles of Incorporation of FirstEnergy Corp. (incorporated by reference to FE's Form 10-Q filed July 23, 2019, Exhibit 3-1, File No. 333-21011).
3-2		Amended and Restated Code of Regulations of FirstEnergy Corp. (incorporated by reference FE's Form 10-Q filed July 23, 2019, Exhibit 3-2, File No. 333-21011).
4-1		Indenture, dated November 15, 2001, between FirstEnergy Corp. and The Bank of New York Mellon, as Trustee (incorporated by reference to FE's Form S-3 filed September 21, 2001, Exhibit 4(a), File No. 333-69856).
4-2		Officer's Certificate relating to FirstEnergy Corp.'s $650 million aggregate principal amount of its 2.75% Notes, Series A, due 2018 and $850 million aggregate principal amount of its 4.25% Notes, Series B, due 2023 (the "Series B Notes") (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.1, File No. 333-21011).
4-2	(a)	Form of Series B Note (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.3, File No. 333-21011).
4-4		Sixth Supplemental Indenture, dated as of December 19, 2016, to Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009, by and between FirstEnergy Nuclear Generation, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to FE's Form 8-K filed December 21, 2016, Exhibit 4.1, File No. 333-21011).
4-4	(a)	Form of First Mortgage Bonds, Collateral Series L of 2016 due 2018 (incorporated by reference to FE's Form 8-K filed December 21, 2016, Exhibit 4.1(a), File No. 333-21011) (included in Exhibit 4-4).
4-5		Ninth Supplemental Indenture, dated as of December 19, 2016, to Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 19, 2008, by and between FirstEnergy Generation, LLC and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A.), as trustee (incorporated by reference to FE's Form 8-K filed December 21, 2016, Exhibit 4.2, File No. 333-21011).
4-5	(a)	Form of First Mortgage Bonds, Collateral Series E of 2016 due 2018 (incorporated by reference to FE's Form 8-K filed December 21, 2016, Exhibit 4.2(a), File No. 333-21011) (included in Exhibit 4-5).
4-6		Officer's Certificate relating to FirstEnergy Corp.'s 2.85% Notes, Series A, due 2022, 3.90% Notes, Series B, due 2027 and 4.85% Notes, Series C, due 2047 (incorporated by reference to FE's Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011).
4-7		Form of 2.85% Note, Series A, due 2022 (incorporated by reference to FE's Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011).
4-8		Form of 3.90% Note, Series B, due 2027 (incorporated by reference to FE's Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011).
4-9		Form of 4.85% Note, Series C, due 2047 (incorporated by reference to FE's Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011).
(A) 4-10		Description of Securities Registered under Section 12(b) of the Securities Exchange Act of 1934.
(B) 10-1		FirstEnergy Corp. 2007 Incentive Plan, effective May 15, 2007 (incorporated by reference to FE's Form 10-K filed February 25, 2009, Exhibit 10.1, File No. 333-21011).
(B) 10-2		Amendment to FirstEnergy Corp. 2007 Incentive Plan, effective January 1, 2011 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.5, File No. 333-21011).
(B) 10-3		Amendment No. 2 to FirstEnergy Corp. 2007 Incentive Plan, effective January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-3, File No. 333-21011).
(B) 10-4		FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, amended and restated January 1, 2005, further amended December 31, 2010 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-6, File No. 333-21011).
(B) 10-5		Amendment No. 1 to Deferred Compensation Plan for Outside Directors, effective as of January 1, 2012 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.7, File No. 333-21011).

(B) 10-6	Amendment No. 2 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, effective January 21, 2014, (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-8, File No. 333-21011).
(B) 10-7	Amendment No. 3 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, dated January 14, 2019 and effective as of April 1, 2018 (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-7, File No.333-21011).

Exhibit Number	
(B) 10-8	FirstEnergy Corp. Supplemental Executive Retirement Plan, amended and restated January 1, 2005, further amended December 31, 2010 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-9, File No. 333-21011).
(B) 10-9	Amendment to FirstEnergy Corp. Supplemental Executive Retirement Plan, effective January 1, 2012 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.8, File No. 333-21011).
(B) 10-10	Amendment No. 2 to FirstEnergy Corp. Supplemental Executive Retirement Plan, dated January 14, 2019 and effective as of April 1, 2018 (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-10, File No. 333-21011).
(B) 10-11	FirstEnergy Corp. Cash Balance Restoration Plan, effective January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-11, File No. 333-21011).
(B) 10-12	Retirement Plan for Outside Directors of GPU, Inc. as amended and restated as of August 8, 2000 (incorporated by reference to GPU, Inc. Form 10-K filed March 21, 2001, Exhibit 10-N, File No. 001-06047).
10-13	Consent Decree dated March 18, 2005 (incorporated by reference to FE's Form 8-K filed March 18, 2005, Exhibit 10-1, File No. 333-21011).
(B) 10-16	Allegheny Energy, Inc. Non-Employee Director Stock Plan (incorporated by reference to FE's Form 8-K filed February 25, 2011, Exhibit 10.4, File No. 21011).
(B) 10-17	Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-29, File No. 333-21011).
(B) 10-18	Amendment No. 1 to Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-30, File No. 333-21011).
(B) 10-19	Form of Director and Officer Indemnification Agreement (incorporated by reference to FE's Form 8-K filed May 16, 2018, Exhibit 10.1, File No. 333-21011).
10-20	Guarantee, dated as of September 16, 2013 by FirstEnergy Corp. in favor of participants under the FirstEnergy Corp. Executive Deferred Compensation Plan (incorporated by reference to FE's Form 10-Q filed November 5, 2013, Exhibit 10.2, File No. 333-21011).
(B) 10-21	Form of Restricted Stock Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-49, File No. 333-21011).
(B) 10-22	FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated July 20, 2015, and effective as of November 1, 2015 (incorporated by reference to FE's Form 8-K filed July 24, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-23	Amendment No. 1 to FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated January 14, 2019 and effective as of April 1, 2018 (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-23, File No. 333-21011).
(B) 10-25	FirstEnergy Corp. 2017 Change in Control Severance Plan, dated as of September 15, 2015, and effective as of January 1, 2017 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-26	Waiver of Participation in the FirstEnergy Corp. Change in Control Severance Plan, entered into by Charles E. Jones dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-27	Non-Competition and Non-Disparagement Agreement, entered into by Charles E. Jones, dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.3, File No. 333-21011).
(B) 10-28	FirstEnergy Corp. 2015 Incentive Compensation Plan (incorporated by reference to FE's Definitive Proxy Statement filed April 1, 2015, Appendix A, File No. 333-21011).

(B) 10-29	Amendment No. 1 to the FirstEnergy Corp. 2015 Incentive Compensation Plan, effective February 21, 2017 (incorporated by reference to FE's Form 10-K filed February 21, 2017, Exhibit 10-51, File No. 333-21011).
(B) 10-32	Form of 2016 Restricted Stock Award Agreement (incorporated by reference to FE's Form 10-K filed February 16, 2016, Exhibit 10-59, File No. 333-21011).
(B) 10-33	Form of 2017-2019 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 21, 2017, Exhibit 10-49, File No. 333-21011).

Exhibit Number	
(B) 10-34	Form of 2017-2019 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 21, 2017, Exhibit 10-50, File No. 333-21011).
(B) 10-35	Form of 2017 Restricted Stock Award Agreement (incorporated by reference to FE's Form 10-K filed February 21, 2017, Exhibit 10-52, File No. 333-21011).
(B) 10-36	Executive Severance Benefits Plan, as amended and restated as of December 20, 2016 (incorporated by reference to FE’s Form 8-K filed December 21, 2016, Exhibit 10.1, File No. 333-21011).
10-37	Credit Agreement, dated as of December 6, 2016, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power Company, as borrowers, Mizuho Bank, Ltd., as administrative agent, and the fronting banks and swing line lenders identified therein (incorporated by reference to FE’s Form 8-K filed December 6, 2016, Exhibit 10.1, File No. 333-21011).
10-38	Amendment No. 1 to Credit Agreement, dated as of October 19, 2018, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power Company, as borrowers, Mizuho Bank, Ltd., as administrative agent, and the fronting banks and swing line lenders identified therein (incorporated by reference to FE’s Form 10-K filed February 19, 2019, Exhibit 10-38, File No. 333-21011).
10-39	Credit Agreement, dated as of December 6, 2016, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated, Mid-Atlantic Interstate Transmission, LLC and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, the banks and the fronting banks identified therein (incorporated by reference to FE’s Form 8-K filed December 6, 2016, Exhibit 10.2, File No. 333-21011).
10-40	Amendment No. 1 to Credit Agreement, dated as of October 19, 2018, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated, Mid-Atlantic Interstate Transmission, LLC and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, the banks and the fronting banks identified therein (incorporated by reference to FE’s Form 10-K filed February 19, 2019, Exhibit 10-40, File No. 333-21011).
10-41	Amendment No. 2 to FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated September 18, 2019 and effective as of November 1, 2015 (incorporated by reference to FE's Form 10-Q filed November 4, 2019, Exhibit 10.3, File No.333-21011).
(B) 10-43	Guarantee, dated as of February 21, 2017, by FirstEnergy Corp. in favor of participants under the FirstEnergy Corp. Cash Balance Pension Restoration Plan (incorporated by reference to FE’s Form 10-Q filed July 27, 2017, Exhibit 10.1, File No. 333-21011).
10-44	Preferred Stock Purchase Agreement, dated January 22, 2018, among FirstEnergy Corp. and the Preferred Investors (incorporated by reference to FE’s Form 8-K filed January 22, 2018, Exhibit 10.1, File No. 333-21011).
10-45	Common Stock Purchase Agreement, dated January 22, 2018, among FirstEnergy Corp. and ZP Master Utility Fund, Ltd., P Zimmer, Ltd., ZP Energy Fund, L.P. and ZP Master Energy Fund, L.P. (incorporated by reference to FE’s Form 8-K filed January 22, 2018, Exhibit 10.2, File No. 333-21011).
(B) 10-46	Form of 2018-2020 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE’s Form 10-K filed February 20, 2018, Exhibit 10-56, File No. 333-21011).
(B) 10-47	Form of 2018-2020 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE’s Form 10-K filed February 20, 2018, Exhibit 10-57, File No. 333-21011).
(B) 10-48	Form of 2018 Restricted Stock Award Agreement (incorporated by reference to FE’s Form 10-K filed February 20, 2018, Exhibit 10-58, File No. 333-21011).
(B) 10-53	FirstEnergy Nuclear Operating Company 2016 Key Employee Retention Plan, effective December 1, 2016 (incorporated by reference to FE’s Form 10-Q filed April 23, 2018, Exhibit 10.7, File No. 333-21011).

(B) 10-54	Amendment to FirstEnergy Nuclear Operating Company 2016 Key Employee Retention Plan, effective March 23, 2017 (incorporated by reference to FE’s Form 10-Q filed April 23, 2018, Exhibit 10.8, File No. 333-21011).
(B) 10-55	Second Amendment to FirstEnergy Nuclear Operating Company 2016 Key Employee Retention Plan, effective December 1, 2017 (incorporated by reference to FE’s Form 10-Q filed April 23, 2018, Exhibit 10.9, File No. 333-21011).
(B) 10-56	Form of FirstEnergy Nuclear Operating Company 2016 Key Employee Retention Agreement (incorporated by reference to FE's Form 10-Q filed April 23, 2018, Exhibit 10.10, File No. 333-21011).

Exhibit Number	
(B) 10-58	Form of 2018-2019 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-Q filed April 23, 2018, Exhibit 10.12, File No. 333-21011).
(B) 10-61	Executive Voluntary Enhanced Retirement Program (incorporated by reference to FE's Form 8-K filed July 23, 2018, Exhibit 10.1, File No. 333-21011).
10-62	Settlement Agreement, dated as of August 26, 2018, by and among the Debtors, the FE Non-Debtor Parties, the Ad Hoc Noteholders Group, the Bruce Mansfield Certificateholders Group and the Committee (in each case, as defined therein) (incorporated by reference to FE's Form 8-K filed August 27, 2018, Exhibit 10.1, File No. 333-21011).
10-63	Term Loan Credit Agreement, dated as of October 19, 2018, among FirstEnergy Corp., the banks and other financial institutions named therein and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-63, File No. 333-21011).
10-64	Term Loan Credit Agreement, dated as of October 19, 2018, among FirstEnergy Corp., the banks and other financial institutions named therein and Bank of Nova Scotia, as administrative agent (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-64, File No. 333-21011).
(B) 10-65	FirstEnergy Solutions Corp. Voluntary Enhanced Retirement Option, effective as of January 2, 2019 (incorporated by reference to FE's Form 8-K filed November 21, 2018, Exhibit 10.1, File No. 333-21011).
(B) 10-67	Form of 2019-2021 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-Q filed April 23, 2019, Exhibit 10.2, File No.333-21011).
(B) 10-68	Form of 2019-2021 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-Q filed April 23, 2019, Exhibit 10.3, File No.333-21011).
(B) 10-69	Form of 2019 Restricted Stock Award Agreement (incorporated by reference to FE's Form 10-Q filed April 23, 2019, Exhibit 10.4, File No.333-21011).
10-70	Amendment No. 1 to Term Loan Credit Agreement, dated as of September 11, 2019, among FirstEnergy Corp., as borrower, the banks and other financial institutions named therein and The Bank of Nova Scotia, as administrative agent (incorporated by reference to FE's Form 8-K filed September 17, 2019, Exhibit 10.1, File No. 333-21011).
10-71	Amendment No. 1 to Term Loan Credit Agreement, dated as of September 11, 2019, among FirstEnergy Corp., as borrower, the banks and other financial institutions named therein and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to FE's Form 8-K filed September 17, 2019, Exhibit 10.2, File No. 333-21011).
10-72	Consent and Waiver to the Settlement Agreement, dated April 18, 2019, by and among the Debtors and the FE Non-Debtor Parties (incorporated by reference to FE's Form 10-Q filed April 23, 2019, Exhibit 10.1, File No.333-21011).
10-73	First Amendment to Settlement Agreement dated November 21, 2019, by and among the Debtors, FE Non-Debtor Parties, Ad Hoc Noteholders Group, Bruce Mansfield Certificateholders Group, and the Committee (incorporated by reference to FE's Form 8-K filed November 26, 2019, Exhibit 10.1, File No. 333-21011).
(A) 21	List of Subsidiaries of the Registrant at December 31, 2019.
(A) 23	Consent of Independent Registered Public Accounting Firm.
(A) 31-1	Certification of chief executive officer, pursuant to Rule 13a-14(a).
(A) 31-2	Certification of chief financial officer, pursuant to Rule 13a-14(a).
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
	The following materials from the Annual Report on Form 10-K for FirstEnergy Corp. for the period ended December 31, 2019, formatted in

101	iXBRL (Inline Extensible Business Reporting Language): (i) Consolidated Statements of Income (Loss) and Consolidated Statements of Comprehensive Income (Loss), (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Stockholders' Equity, (iv) Consolidated Statements of Cash Flows, (v) related notes to these financial statements and (vi) document and entity information.
104	Cover Page Interactive Data File (the cover page XBRL tags are embedded within the Inline XBRL document)

(A) Provided herein in electronic format as an exhibit.
(B) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, FirstEnergy has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but hereby agrees to furnish to the SEC on request any such documents.

ITEM 16. FORM 10-K SUMMARY

None.

SCHEDULE II

FIRSTENERGY CORP.

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017

Description		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts (1)	Deductions (2)	Ending Balance
				(In thousands)		
Year Ended December 31, 2019:						
Accumulated provision for uncollectible accounts	— customers	$ 49,798	$ 81,107	$ 47,306	$ 132,031	$ 46,180
	— other	$ 1,778	$ 26,654	$ 1,474	$ 8,509	$ 21,397
	— affiliated companies (4)	$919,851	$143,276	$ —	$ —	$1,063,127
Valuation allowance on various DTAs (3)		$394,112	$ 46,526	$ —	$ —	$ 440,638
Year Ended December 31, 2018:						
Accumulated provision for uncollectible accounts	— customers	$ 48,937	$ 77,254	$ 60,307	$ 136,700	$ 49,798
	— other	$ 990	$ 12,487	$ —	$ 11,699	$ 1,778
	— affiliated companies (4)	$ —	$ —	$ —	$ 919,851	$ 919,851
Valuation allowance on state and local DTAs		$312,135	$ 81,977	$ —	$ —	$ 394,112
Year Ended December 31, 2017:						
Accumulated provision for uncollectible accounts	— customers	$ 48,409	$ 73,486	$ 49,728	$ 122,686	$ 48,937
	— other	$ 884	$ 6,461	$ —	$ 6,355	$ 990
Valuation allowance on state and local DTAs		$240,289	$ 71,846	$ —	$ —	$ 312,135

(1) Represents recoveries and reinstatements of accounts previously written off for uncollectible accounts.

(2) Represents the write-off of accounts considered to be uncollectible.

(3) Starting in 2018, valuation allowances are now being recorded against federal and state DTA's related to disallowed business interest and certain employee remuneration, in addition to the state and local DTA's in the prior years presented.

(4) Amounts relate to the FES Debtors and are included in discontinued operations. See Note 3, "Discontinued Operations" for additional information.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

FIRSTENERGY CORP.

BY: /s/ Charles E. Jones

Charles E. Jones

President and Chief Executive Officer

Date: February 10, 2020

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Charles E. Jones
Charles E. Jones
President and Chief Executive Officer and Director
(Principal Executive Officer)

/s/ Donald T. Misheff
Donald T. Misheff
Director
(Non-Executive Chairman of Board)

/s/ Steven E. Strah
Steven E. Strah
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Jason J. Lisowski
Jason J. Lisowski
Vice President, Controller and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Michael J. Anderson
Michael J. Anderson
Director

/s/ Christopher D. Pappas
Christopher D. Pappas
Director

/s/ Steven J. Demetriou
Steven J. Demetriou
Director

/s/ Sandra Pianalto
Sandra Pianalto
Director

/s/ Julia L. Johnson
Julia L. Johnson
Director

/s/ Luis A. Reyes
Luis A. Reyes
Director

/s/ Thomas N. Mitchell
Thomas N. Mitchell
Director

/s/ Leslie M. Turner
Leslie M. Turner
Director

/s/ James F. O'Neil III
James F. O'Neil III
Director

Date: February 10, 2020

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Section 2: EX-4.10 (EXHIBIT 4.10)

Exhibit 4-10

DESCRIPTION OF SECURITIES

Certain provisions of the Amended and Restated Articles of Incorporation and Amended and Restated Code of Regulations of FirstEnergy Corp., an Ohio corporation ("***FE***" and, collectively with its consolidated subsidiaries, "***FirstEnergy***"), are summarized or referred to below. The summaries may not contain all of the information that may be important to investors, do not relate to or give effect to the provisions of statutory or common law, and are qualified in their entirety by express reference to FE's Amended and Restated Articles of Incorporation and Amended and Restated Code of Regulations.

General

FE is authorized by its Amended and Restated Articles of Incorporation to issue 700,000,000 shares of common stock, $0.10 par value per share. FE is also authorized by its Amended and Restated Articles of Incorporation to issue 5,000,000 shares of preferred stock, $100 par value per share.

FE's Amended and Restated Articles of Incorporation give its board of directors authority to issue preferred stock from time to time in one or more classes or series and to fix the designations, powers, preferences, limitations and relative rights of any series of preferred stock that it chooses to issue, including, without limitation, dividend rates, conversion rights, voting rights, terms of redemption and liquidation preferences and the number of shares constituting each such series. Such preferred stock could be issued with terms that could delay, defer or prevent a change of control of FirstEnergy. Prior to the issuance of a new series of preferred stock, FE will amend its Amended and Restated Articles of Incorporation, designating the stock of that series and the terms of that series. FE will describe the terms of the preferred stock in the prospectus supplement for such offering, as applicable, and will file a copy of the amendment to its Amended and Restated Articles of Incorporation establishing the terms of the preferred stock with the Securities and Exchange Commission.

Dividend Rights

Subject only to any prior rights and preferences of any shares of FE's preferred stock that are or may in the future be issued and outstanding, the holders of FE's common stock are entitled to receive dividends when, as and if declared by FE's board of directors out of legally available funds.

Liquidation Rights

In the event of FE's dissolution or liquidation, the holders of its common stock will be entitled to receive, pro rata, after the prior rights of the holders of any issued and outstanding shares of its preferred stock have been satisfied, all of its assets that remain available for distribution after payment in full of all of its liabilities.

Voting Rights

The holders of FE's common stock are entitled to one vote on each matter submitted for their vote at any meeting of FE's stockholders for each share of FE's common stock held as of the record date for the meeting. Under FE's Amended and Restated Articles of Incorporation, the voting rights of its preferred stock may differ from the voting rights of its common stock. The holders of FE's common stock are not entitled to cumulate their votes for the election of directors.

Adoption of amendments to FE's Amended and Restated Articles of Incorporation, adoption of a plan of merger, consolidation or reorganization, authorization of a sale or other disposition of all or substantially all of FE’s assets not made in the usual and regular course of its business or adoption of a resolution of dissolution, and any other matter that would otherwise require a two-thirds approving vote, require the approval of a majority of the voting power of FE’s outstanding shares.

In addition, the approval of a majority of the voting power of FE’s outstanding shares must be obtained to amend or repeal the provisions of its Amended and Restated Code of Regulations.

Ohio Law Anti-takeover Provisions

Several provisions of the Ohio Revised Code (“***ORC***”) may make it more difficult to acquire FirstEnergy by means of a tender offer, open market purchase, proxy fight or otherwise. These provisions include Chapter 1704 (Business Combinations), Section 1701.831 (Control Share Acquisitions) and Section 1707.041 (Control Bids). The ORC’s Business Combination, Control Share Acquisition and Control Bids provisions are set forth in summary below. This summary may not contain all the information that is important to investors and is subject to, and is qualified in its entirety by reference to, all sections of the ORC.

Chapter 1704 of the ORC applies to a broad range of business combinations between an Ohio corporation and an interested stockholder. The Ohio law definition of “business combination” includes mergers, consolidations, combinations or majority share acquisitions. An “interested stockholder” is defined as a stockholder who, directly or indirectly, exercises or directs the exercise of 10% or more of the voting power of the corporation in the election of directors.

Chapter 1704 restricts corporations from engaging in business combinations with interested stockholders, unless the articles of incorporation provide otherwise, for a period of three years following the date on which the stockholder became an interested stockholder, unless the directors of the corporation have approved the business combination or the interested stockholder’s acquisition of shares of the corporation prior to the date the stockholder became an interested stockholder. After the initial three-year moratorium, Chapter 1704 prohibits such transactions absent approval by the directors of the interested stockholder’s acquisition of shares of the corporation prior to the date that the stockholder became an interested stockholder, approval by disinterested stockholders of the corporation or the transaction meeting certain statutorily defined fair price provisions.

Under Section 1701.831 of the ORC, unless the articles of incorporation, the regulations adopted by the stockholders, or the regulations adopted by the directors pursuant to division (A)(1) of Section 1701.10 of the ORC provide otherwise, any control share acquisition of a corporation can only be made with the prior approval of the corporation’s disinterested stockholders. A “control share acquisition” is defined as the acquisition, directly or indirectly, by any person of shares of a corporation that, when added to all other shares of that corporation in respect of which the person may exercise or direct the exercise of voting power, would enable that person, immediately after the acquisition, directly or indirectly, alone or with others, to exercise levels of voting power of the corporation in the election of directors in any of the following ranges: at least 20% but less than $33\frac{1}{3}$%; at least $33\frac{1}{3}$% but no more than 50%; or more than 50%.

FE has not opted out of the application of either Chapter 1704 or Section 1701.831.

Section 1707.041 of the ORC regulates certain “control bids” for corporations in Ohio with certain concentrations of Ohio stockholders and permits the Ohio Division of Securities to suspend a control bid if certain information is not provided to offerees, the subject corporation and the Ohio Division of Securities. Control bids include the purchase of or offer to purchase any equity security of such a corporation from a resident of Ohio if, after the purchase of that security, the offeror would be directly or indirectly the beneficial owner of more than 10% of any class of issued and outstanding equity securities of the corporation. Information that must be provided in connection with a control bid includes a statement of any plans or proposals that the offeror, upon gaining control, may have to liquidate the subject corporation, sell its assets, effect a merger or consolidation of the corporation, establish, terminate, convert, or amend employee benefit plans, close any plant or facility of the subject corporation or of any of its subsidiaries or affiliates, change or reduce its work force or the work force of any of its subsidiaries or affiliates, or make any other major change in the corporation's business, corporate structure, management personnel or policies of employment.

Anti-takeover Effects

The rights or the provisions of Ohio law described above, individually or collectively, may discourage, deter, delay or impede a tender offer or other attempt to acquire control of FirstEnergy even if the transaction would result in the stockholders receiving a premium for their shares over current market prices or if the stockholders otherwise believe the transaction would be in their best interests.

In addition, FE's Amended and Restated Code of Regulations contains certain advance notice provisions with which stockholders must comply in order to bring business before an annual meeting of stockholders or nominate candidates for FE's board of directors.

Preemptive or Conversion Rights

Holders of FE's common stock have no preemptive or conversion rights and are not subject to further calls or assessments by FE. There are no redemption or sinking fund provisions applicable to FE's common stock.

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Section 3: EX-21 (EXHIBIT 21)

EXHIBIT 21

FIRSTENERGY CORP.
LIST OF SUBSIDIARIES OF THE REGISTRANT
AT DECEMBER 31, 2019

FirstEnergy Nuclear Operating Company - Incorporated in Ohio[(1)]

FirstEnergy Service Company - Incorporated in Ohio

FirstEnergy Solutions Corp. - Incorporated in Ohio[(1)]

FirstEnergy Transmission, LLC - Organized in Delaware

FirstEnergy Ventures Corp. - Incorporated in Ohio

Jersey Central Power & Light Company - Incorporated in New Jersey

Metropolitan Edison Company - Incorporated in Pennsylvania

Monongahela Power Company - Incorporated in Ohio

Ohio Edison Company - Incorporated in Ohio

Pennsylvania Electric Company - Incorporated in Pennsylvania

The Cleveland Electric Illuminating Company - Incorporated in Ohio

The Potomac Edison Company - Incorporated in Maryland

The Toledo Edison Company - Incorporated in Ohio

West Penn Power Company - Incorporated in Pennsylvania

(1) As of March 31, 2018, the noted subsidiaries no longer consolidated into FE Corp.

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Section 4: EX-23 (EXHIBIT 23)

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-233340, 333-223509, 333-223473, 333-223472, and 333-48587) and Form S-8 (Nos. 333-226788, 333-222225, 333-204436, 333-202184, 333-172464, 333-165640, 333-146170, 333-101472, 333-89356, 333-72768, 333-56094, and 333-81183) of FirstEnergy Corp. of our report dated February 10, 2020 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Cleveland, Ohio
February 10, 2020

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Section 5: EX-31.1 (EXHIBIT 31.1)

EXHIBIT 31.1

Certification

I, Charles E. Jones, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2020

/s/ Charles E. Jones

Charles E. Jones

President and Chief Executive Officer

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Section 6: EX-31.2 (EXHIBIT 31.2)

EXHIBIT 31.2

Certification

I, Steven E. Strah, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2020

/s/ Steven E. Strah

Steven E. Strah

Senior Vice President and Chief Financial Officer

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Section 7: EX-32 (EXHIBIT 32)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Corp. ("Company") on Form 10-K for the period ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles E. Jones

Charles E. Jones

President and Chief Executive Officer

/s/ Steven E. Strah

Steven E. Strah

Senior Vice President and Chief Financial Officer

Date: February 10, 2020

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