FIRSTENERGY CORP
Form 10-Q
October 26, 2017

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

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

For the quarterly period ended September 30, 2017

OR

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

For the transition period from ____________________ to ____________________

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 þ FirstEnergy Corp.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standard provided pursuant to Section 13(a) of the Exchange Act. o

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

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

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

CLASS	OUTSTANDING AS OF SEPTEMBER 30, 2017
FirstEnergy Corp., $0.10 par value	444,858,003
FirstEnergy Solutions Corp., no par value	7

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

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

FirstEnergy Web Site and Other Social Media Sites and Applications

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

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

OMISSION OF CERTAIN INFORMATION

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

Forward-Looking Statements: This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "forecast," "target," "will," "intend," “believe,” "project," “estimate," "plan" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following:

- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and the effectiveness of our strategy to transition to a fully regulated business profile.
- The accomplishment of our regulatory and operational goals in connection with our transmission and distribution investment plans, including, but not limited to, our planned transition to forward-looking formula rates.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet.
- Success of legislative and regulatory solutions for generation assets that recognize their environmental or energy security benefits, including the NOPR released by the Secretary of Energy and action by FERC.
- The risks and uncertainties associated with the lack of viable alternative strategies regarding the CES segment, thereby causing FES, and likely FENOC, to restructure its substantial debt and other financial obligations with its creditors or seek protection under U.S. bankruptcy laws and the losses, liabilities and claims arising from such bankruptcy proceeding, including any obligations at FirstEnergy.
- The risks and uncertainties at the CES segment, including FES, and its subsidiaries, and FENOC, related to wholesale energy and capacity markets and the viability and/or success of strategic business alternatives, such as pending and potential CES generating unit asset sales, the potential conversion of the remaining generation fleet from competitive operations to a regulated or regulated-like construct or the potential need to deactivate additional generating units, which could result in further substantial write-downs and impairments of assets.
- The substantial uncertainty as to FES’ ability to continue as a going concern and substantial risk that it may be necessary for FES, and likely FENOC, to seek protection under U.S. bankruptcy laws.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments, such as long-term fuel and transportation agreements.
- The uncertainties associated with the deactivation of older regulated and competitive units, including the impact on vendor commitments, such as long-term fuel and transportation agreements, and as it relates to the reliability of the transmission grid, the timing thereof.
- The impact of other future changes to the operational status or availability of our generating units and any capacity performance charges associated with unit unavailability.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil prices, and their availability and impact on margins.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Replacement power costs being higher than anticipated or not fully hedged.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation, or potential regulatory initiatives or rulemakings (including that such initiatives or

rulemakings could result in our decision to deactivate or idle certain generating units).

- Changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- Economic or weather conditions affecting future sales, margins and operations such as a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of labor disruptions by our unionized workforce.
- The risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks.
- The impact of the regulatory process and resulting outcomes on the matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM markets and FERC-jurisdictional wholesale transactions; FERC

regulation of cost-of-service rates; and FERC’s compliance and enforcement activity, including compliance and enforcement activity related to NERC’s mandatory reliability standards.

- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Other legislative and regulatory changes, including the new federal administration's required review and potential revision of environmental requirements, including, but not limited to, the effects of the EPA's CPP, CCR, CSAPR and MATS programs, including our estimated costs of compliance, CWA waste water effluent limitations for power plants, and CWA 316(b) water intake regulation.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to, the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building at Davis-Besse.
- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to significant accounting policies.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- The ability to access the public securities and other capital and credit markets in accordance with our financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Further actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries’ access to financing, increase the costs thereof, increase requirements to post additional collateral to support, or accelerate payments under outstanding commodity positions, LOCs and other financial guarantees, and the impact of these events on the financial condition and liquidity of FirstEnergy and/or its subsidiaries, specifically FES and its subsidiaries.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

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

These forward-looking statements are also qualified by, and should be read together with, the risk factors included in FirstEnergy's and FES' filings with the SEC, including but not limited to the most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. The foregoing review of factors also should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

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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. As of January 1, 2014, AE merged with and into FirstEnergy Corp.
AESC	Allegheny Energy Service Corporation, a subsidiary of FirstEnergy Corp.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and equity method investee of MP
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities
BU Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply, and 50% owner in a joint venture that owns the Buchanan Generating Facility
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FENOC	FirstEnergy Nuclear Operating Company, a subsidiary of FE, which operates NG's nuclear generating facilities
FES	FirstEnergy Solutions Corp., together with its consolidated subsidiaries, which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, which is the parent of ATSI, TrAIL and MAIT, and has a joint venture in PATH
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	Global Rail Group, LLC, a subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, which owns and operates transmission facilities
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
NG	FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline, LLC, a joint venture between FE and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	

	The Potomac Edison Company, a Maryland and West Virginia electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Signal Peak	Signal Peak Energy, LLC, an indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

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

AAA	American Arbitration Association
ADIT	Accumulated Deferred Income Taxes
AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction

GLOSSARY OF TERMS, Continued

ALJ	Administrative Law Judge
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASU	Accounting Standards Update
BGS	Basic Generation Service
BNSF	BNSF Railway Company
CAA	Clean Air Act
CCR	Coal Combustion Residuals
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCR	Delivery Capital Recovery
DMR	Distribution Modernization Rider
DOE	United States Department of Energy
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP IV	Electric Security Plan IV
ESP IV PPA	Unit Power Agreement entered into on April 1, 2016 by and between the Ohio Companies and FES
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
HCl	Hydrochloric Acid
ICE	Intercontinental Exchange, Inc.
IRP	Integrated Resource Plan

IRS	Internal Revenue Service
kV	Kilovolt
KWH	Kilowatt-hour
LOC	Letter of Credit
LS Power	LS Power Equity Partners III, LP
LTIIPs	Long-Term Infrastructure Improvement Plans
MATS	Mercury and Air Toxics Standards

GLOSSARY OF TERMS, Continued

MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master Limited Partnership
mmBTU	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MVP	Multi-Value Project
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NJAPA	New Jersey Administrative Procedure Act
NJBPU	New Jersey Board of Public Utilities
NOL	Net Operating Loss
NOPR	Notice of Proposed Rulemaking
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NS	Norfolk Southern Corporation
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
Regulation FD	Regulation Fair Disclosure promulgated by the SEC

REIT	Real Estate Investment Trust
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity

GLOSSARY OF TERMS, Continued

RRS	Retail Rate Stability
RSS	Rich Site Summary
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Service
SB310	Substitute Ohio Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
Sixth Circuit	United States Court of Appeals for the Sixth Circuit
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
Twitter®	Twitter is a registered trademark of Twitter, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VEPCO	Virginia Electric and Power Company
VIE	Variable Interest Entity
VMP	Vegetation Management Plan
VMS	Vegetation Management Surcharge
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(Unaudited)

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
(In millions, except per share amounts)	2017	2016	2017	2016
REVENUES:				
Regulated Distribution	$2,610	$2,691	$7,362	$7,390
Regulated Transmission	342	294	982	851
Unregulated businesses	762	932	2,231	2,946
Total revenues*	3,714	3,917	10,575	11,187
OPERATING EXPENSES:				
Fuel	363	450	1,074	1,269
Purchased power	861	979	2,459	2,992
Other operating expenses	942	953	3,041	2,835
Provision for depreciation	289	311	845	974
Amortization of regulatory assets, net	91	98	215	222
General taxes	253	265	777	786
Impairment of assets (Note 14)	31	—	162	1,447
Total operating expenses	2,830	3,056	8,573	10,525
OPERATING INCOME	884	861	2,002	662
OTHER INCOME (EXPENSE):				
Investment income	37	28	78	75
Interest expense	(305)	(286)	(882)	(863)
Capitalized financing costs	19	28	59	79
Total other expense	(249)	(230)	(745)	(709)
INCOME (LOSS) BEFORE INCOME TAXES	635	631	1,257	(47)
INCOME TAXES	239	251	482	334
NET INCOME (LOSS)	$396	$380	$775	$(381)
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:				
Basic	$0.89	$0.89	$1.75	$(0.90)
Diluted	$0.89	$0.89	$1.74	$(0.90)
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	444	425	444	425

Diluted	446	427	445	425
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.72	$0.72	$1.44	$1.44

* Includes excise tax collections of $102 million and $111 million in the three months ended September 30, 2017 and 2016, respectively, and $293 million and $310 million in the nine months ended September 30, 2017 and 2016, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
(In millions)	2017	2016	2017	2016
NET INCOME (LOSS)	$396	$380	$775	$(381)
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(19)	(18)	(55)	(54)
Amortized losses on derivative hedges	4	2	8	6
Change in unrealized gains on available-for-sale securities	(6)	4	8	67
Other comprehensive income (loss)	(21)	(12)	(39)	19
Income taxes (benefits) on other comprehensive income (loss)	(9)	(5)	(16)	6
Other comprehensive income (loss), net of tax	(12)	(7)	(23)	13
COMPREHENSIVE INCOME (LOSS)	$384	$373	$752	$(368)

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 399	$ 199
Receivables-		
Customers, net of allowance for uncollectible accounts of $52 in 2017 and $53 in 2016	1,370	1,440
Other, net of allowance for uncollectible accounts of $1 in 2017 and 2016	172	175
Materials and supplies	543	564
Prepaid taxes	123	98
Derivatives	35	140
Collateral	146	176
Other	143	158
	2,931	2,950
PROPERTY, PLANT AND EQUIPMENT:		
In service	44,229	43,767
Less — Accumulated provision for depreciation	16,086	15,731
	28,143	28,036
Construction work in progress	1,355	1,351
	29,498	29,387
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,632	2,514
Other	511	512
	3,143	3,026
ASSETS HELD FOR SALE (Note 14)	788	—
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	5,618
Regulatory assets	929	1,014
Other	742	1,153
	7,289	7,785
	$ 43,649	$ 43,148
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,076	$ 1,685
Short-term borrowings	500	2,675
Accounts payable	924	1,043
Accrued taxes	520	580
Accrued compensation and benefits	337	363
Collateral	31	42
Other	867	738
	4,255	7,126
CAPITALIZATION:		
Common stockholders' equity-		
	44	44

Common stock, $0.10 par value, authorized 700,000,000 shares - 444,858,003 and 442,344,218 shares outstanding as of September 30, 2017 and December 31, 2016, respectively		
Other paid-in capital	9,974	10,555
Accumulated other comprehensive income	151	174
Accumulated deficit	(3,763)	(4,532)
Total common stockholders' equity	6,406	6,241
Long-term debt and other long-term obligations	21,089	18,192
	27,495	24,433
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	4,225	3,765
Retirement benefits	3,814	3,719
Asset retirement obligations	1,550	1,482
Deferred gain on sale and leaseback transaction	732	757
Adverse power contract liability	143	162
Other	1,435	1,704
	11,899	11,589
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$ 43,649	$ 43,148

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	For the Nine Months Ended September 30 2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (Loss)	$775	$(381)
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	1,248	1,477
Deferred purchased power and other costs	55	(34)
Deferred income taxes and investment tax credits, net	453	318
Impairment of assets (Note 14)	162	1,447
Investment impairments	10	13
Deferred costs on sale leaseback transaction, net	37	36
Retirement benefits, net of payments	28	45
Pension trust contributions	—	(297)
Unrealized (gain) loss on derivative transactions (Note 8)	64	(10)
Lease payments on sale and leaseback transaction	(47)	(94)
Changes in current assets and liabilities-		
Receivables	73	(34)
Materials and supplies	(6)	45
Prepaid taxes and other current assets	(41)	(28)
Accounts payable	(22)	(17)
Accrued taxes	(161)	(81)
Accrued compensation and benefits	(54)	2
Other current liabilities	13	53
Collateral, net	19	25
Other	156	107
Net cash provided from operating activities	2,762	2,592
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	4,050	521
Short-term borrowings, net	—	1,275
Redemptions and Repayments-		
Long-term debt	(1,711)	(1,017)
Short-term borrowings, net	(2,175)	—
Common stock dividend payments	(478)	(458)
Other	(67)	(17)
Net cash (used for) provided from financing activities	(381)	304
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,847)	(2,156)
Nuclear fuel	(156)	(195)
Sales of investment securities held in trusts	1,923	1,361
Purchases of investment securities held in trusts	(1,995)	(1,437)

Asset removal costs	(130)	(101)
Other	24	52
Net cash used for investing activities	(2,181)	(2,476)
Net change in cash and cash equivalents	200	420
Cash and cash equivalents at beginning of period	199	131
Cash and cash equivalents at end of period	$399	$551

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

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

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
(In millions)	2017	2016	2017	2016
STATEMENTS OF INCOME (LOSS)				
REVENUES:				
Electric sales to non-affiliates	$653	$952	$2,056	$2,917
Electric sales to affiliates	88	111	279	360
Other	2	37	63	124
Total revenues	743	1,100	2,398	3,401
OPERATING EXPENSES:				
Fuel	165	202	463	595
Purchased power from affiliates	—	191	202	440
Purchased power from non-affiliates	152	186	468	829
Other operating expenses	291	316	1,095	925
Provision for depreciation	28	83	80	250
General taxes	5	21	44	66
Impairment of assets (Note 14)	—	—	—	540
Total operating expenses	641	999	2,352	3,645
OPERATING INCOME (LOSS)	102	101	46	(244)
OTHER INCOME (EXPENSE):				
Investment income	39	24	74	56
Miscellaneous income	1	1	6	4
Interest expense — affiliates	(6)	(3)	(13)	(6)
Interest expense — other	(34)	(36)	(104)	(109)
Capitalized interest	6	9	20	27
Total other income (expense)	6	(5)	(17)	(28)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	108	96	29	(272)
INCOME TAXES (BENEFITS)	32	56	14	(5)
NET INCOME (LOSS)	$76	$40	$15	$(267)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)				
NET INCOME (LOSS)	$76	$40	$15	$(267)
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(3)	(3)	(10)	(10)

Amortized gains on derivative hedges	1	1	1	—
Change in unrealized gains on available-for-sale securities	(6)	5	16	61
Other comprehensive income (loss)	(8)	3	7	51
Income taxes (benefits) on other comprehensive income (loss)	(3)	1	2	20
Other comprehensive income (loss), net of tax	(5)	2	5	31
COMPREHENSIVE INCOME (LOSS)	$71	$42	$20	$(236)

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $3 in 2017 and $5 in 2016	171	213
Affiliated companies	327	452
Other	13	27
Notes receivable from affiliated companies	—	29
Materials and supplies	263	267
Derivatives	31	137
Collateral	126	157
Prepaid taxes and other	29	63
	962	1,347
PROPERTY, PLANT AND EQUIPMENT:		
In service	7,443	7,057
Less — Accumulated provision for depreciation	6,123	5,929
	1,320	1,128
Construction work in progress	288	427
	1,608	1,555
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,823	1,552
Other	9	10
	1,832	1,562
DEFERRED CHARGES AND OTHER ASSETS:		
Property taxes	6	40
Accumulated deferred income taxes	2,057	2,279
Derivatives	5	77
Other	369	381
	2,437	2,777
	$ 6,839	$ 7,241
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 267	$ 179
Short-term borrowings - affiliated companies	186	101
Accounts payable-		
Affiliated companies	230	550
Other	98	110
Accrued taxes	32	143
Derivatives	12	77
Other	167	156
	992	1,316
CAPITALIZATION:		
Common stockholder's equity-		
	3,748	3,658

Common stock, without par value, authorized 750 shares - 7 shares outstanding as of September 30, 2017 and December 31, 2016		
Accumulated other comprehensive income	74	69
Accumulated deficit	(3,494)	(3,509)
Total common stockholder's equity	328	218
Long-term debt and other long-term obligations	2,559	2,813
	2,887	3,031
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	732	757
Retirement benefits	207	197
Asset retirement obligations (Note 9)	988	901
Other	1,033	1,039
	2,960	2,894
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$ 6,839	$ 7,241

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Nine Months Ended September 30	
(In millions)	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (Loss)	$15	$(267)
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel, intangible assets and deferred debt-related costs	245	485
Deferred costs on sale and leaseback transaction, net	37	36
Deferred income taxes and investment tax credits, net	156	90
Investment impairments	10	12
Pension trust contribution	—	(138)
Unrealized (gain) loss on derivative transactions (Note 8)	64	(10)
Lease payments on sale and leaseback transaction	(47)	(94)
Impairment of assets (Note 14)	—	540
Changes in current assets and liabilities-		
Receivables	198	19
Materials and supplies	(24)	25
Prepaid taxes and other current assets	37	(3)
Accounts payable	(210)	(69)
Accrued taxes	(117)	(6)
Other current liabilities	(11)	13
Collateral, net	31	6
Other	74	(34)
Net cash provided from operating activities	458	605
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	—	471
Short-term borrowings, net	85	101
Redemptions and repayments-		
Long-term debt	(163)	(503)
Other	(5)	(8)
Net cash (used for) provided from financing activities	(83)	61
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(201)	(432)
Nuclear fuel	(156)	(195)
Sales of investment securities held in trusts	834	576
Purchases of investment securities held in trusts	(878)	(619)

Loans to affiliated companies, net	29	(15)
Other	(3)	19
Net cash used for investing activities	(375)	(666)
Net change in cash and cash equivalents	—	—
Cash and cash equivalents at beginning of period	2	2
Cash and cash equivalents at end of period	$2	$2
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction: Affiliated net asset transfer (Note 9)	$73	$28

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

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

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 organized under the laws of the State of Ohio in 1996. FE's principal business is the holding, directly or indirectly, of all of the outstanding equity of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI, MAIT and TrAIL), and AESC. In addition, FE holds all of the outstanding equity of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and Allegheny Ventures, Inc.

FE and its subsidiaries are principally involved in the generation, transmission, and distribution of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, based on serving over six million customers in the Midwest and Mid-Atlantic regions. Its regulated and unregulated generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,500 miles of lines and two regional transmission operation centers.
FES, a subsidiary of FE, was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to retail and wholesale customers. FES also owns and operates, through its FG subsidiary, fossil generating facilities and owns, through its NG subsidiary, nuclear generating facilities, which are operated by FENOC. FES purchases the entire output of the generation facilities owned by FG and NG. Prior to April 1, 2016, FES financially purchased the uncommitted output of AE Supply's generation facilities under a PSA. On December 21, 2015, FES agreed, under a PSA, to physically purchase all the output of AE Supply's generation facilities effective April 1, 2016. FES and AE Supply terminated the PSA effective on April 1, 2017. FES complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NRC and applicable state regulatory authorities.

These interim financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and disclosures normally included in financial statements and notes prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These interim financial statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2016. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

FirstEnergy follows GAAP and complies 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 accompanying interim financial statements are unaudited, but reflect all adjustments, consisting of normal recurring adjustments, that, in the opinion of management, are necessary for a fair statement of the financial statements. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not necessarily indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation as appropriate. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 6, "Variable Interest Entities"). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but do not have a controlling financial interest, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage of FE's ownership share of the entity’s earnings is reported in the Consolidated Statements of Income and Comprehensive Income.

For each of the three months ended September 30, 2017 and 2016, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $8 million and $11 million, respectively, of allowance for equity funds used during construction and $11 million and $17 million, respectively, of capitalized interest. For each of the nine months ended September 30, 2017 and 2016, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $25 million and $28 million, respectively, of allowance for equity funds used during construction and $34 million and $51 million, respectively, of capitalized interest.

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

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

Strategic Review of Competitive Operations

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

Over the past several years, CES has been impacted by a decrease in demand and excess generation supply in the PJM Region, which has resulted in low power and capacity prices, as well as significant environmental compliance costs. To address this, CES sold or deactivated more than 6,770 MWs of competitive generation from 2012 to 2015 and announced in 2016 plans to exit and/or deactivate an additional 856 MWs by 2020 related to the Bay Shore Unit 1 generating station and Units 1-4 of the W.H. Sammis generating station. Additionally, CES has continued to focus on cost reductions, including those identified as part of FirstEnergy’s previously disclosed cash flow improvement plan.

However, the energy and capacity markets remain weak with significantly low capacity clearing prices and current forward pricing as well as the long-term fundamental view on energy and capacity prices. In order to focus on stable and predictable cash flow from its regulated business units, in November of 2016, FirstEnergy announced a strategic review of its competitive operations with a target to implement its exit from competitive operations by mid-2018.

In connection with this strategic review, AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating Facility and approximately 59% of AGC’s interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments. Closing of the transaction is subject to customary and other closing conditions including receipt of regulatory approvals from FERC and the VSCC, third party consents and the satisfaction and discharge of $305 million of AE Supply’s senior notes, which is expected to require the payment of a “make-whole” premium currently estimated to be approximately $100 million based on current interest rates, upon both (i) the consummation of the sale of the natural gas generating plants and (ii) either (a) the consummation of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station or (b) the consummation of the pending sale of the Pleasants Power Station by AE Supply to its affiliate, MP, as discussed below. As a further condition to closing, FE will provide the purchaser two limited three-year guarantees of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement. The sale of the natural gas generating plants is expected to close in the fourth quarter of 2017 and the sale of approximately 59% of AGC’s interests in the Bath County hydroelectric power station and BU Energy’s 50% interest in the Buchanan Generating Facility are expected to close in the first quarter of 2018. For additional information see Note 14, "Asset Impairments."

Additionally, AE Supply’s Pleasants power station (1,300 MWs) was selected in MP's RFP seeking additional generation capacity, and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire the Pleasants power station for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals as further discussed below in Note 10, "Regulatory Matters - State Regulation - West Virginia."

The strategic options to exit the remaining portion of CES’ generation, which is primarily at FES, are still uncertain, but could include one or more of the following:

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

- additional asset sales and/or plant deactivations.

Furthermore, the implementation of various strategic options, and the timing thereof, could be impacted by various events, including, but not limited to the following:

- The outcome of efforts related to the NOPR released by the Secretary of Energy and action by FERC to address critical issues central to protecting the long-term reliability and resiliency of the electric grid provided by traditional baseload resources, such as coal and nuclear generation;
- The resolution of legislation before the Ohio General Assembly that would create a zero-emission nuclear (ZEN) program that would provide compensation to nuclear power plants for their fuel diversity, environmental and other benefits and the potential for similar legislative action in Pennsylvania; and/or
- The inability to finalize and consummate a settlement agreement with BNSF and NS regarding a previously disclosed long-term coal transportation contract dispute as discussed in Note 11, "Commitments, Guarantees and Contingencies - Environmental Matters" below, whereby FG could be subject to materially higher damages.

Today, the competitive generation portfolio is comprised of more than 13,000 MWs of generation, primarily from coal, nuclear and natural gas and oil fuel sources. The assets can generate approximately 70-75 million MWHs annually, with up to an additional five million MWHs available from purchased power agreements for wind, solar, and CES' entitlement in OVEC, of which a portion is sold through various retail channels and the remainder targeting forward wholesale or spot sales. Subject to the completion of the AE Supply and AGC asset sale discussed above as well as the transfer of the Pleasants Power station to MP, the size and generation capacity of CES’ portfolio will be reduced to approximately 10,000 MWs, primarily at FES, with up to approximately 65 million MWHs produced annually.

The competitive business continues to be managed conservatively due to the stress of weak energy prices, insufficient results from recent capacity auctions and anemic demand forecasts. Furthermore, the credit quality of CES, specifically FES' unsecured debt rating of Caa1 at Moody’s, CCC- at S&P and C at Fitch and a negative outlook from Moody's and S&P, has challenged its ability to hedge generation with retail and forward wholesale sales due to significant collateral requirements. As a result, CES' contract sales are expected to decline from 53 million MWHs in 2016 to 40-45 million MWHs in 2017 and to 30-35 million MWHs in 2018. While the reduced contract sales will decrease potential collateral requirements, market price volatility may significantly impact CES' financial results due to the increased exposure to the wholesale spot market.

Going Concern at FES

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of September 30, 2017, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. Furthermore, an inability to develop and execute upon viable alternative strategies for its competitive portfolio would continue to further stress the liquidity and financial condition of FES.

Cash flow from operations at FES is expected to be sufficient to fund capital expenditures, nuclear fuel purchases, and repay money pool borrowings through March 2018. However, as previously disclosed, FES has $515 million of maturing debt in 2018, beginning in the second quarter. Additionally, FES has $48 million of interest and lease payments in December 2017 and $38 million of interest payments in the first quarter of 2018. Based on FES' current senior unsecured debt rating, capital structure and the forecasted decline in wholesale forward market prices over the next few years, the debt maturities are likely to be difficult to refinance. Furthermore, lack of clarity regarding the timing and viability of alternative strategies, including additional asset sales or deactivations and/or converting generation from competitive operations to a regulated or regulated-like construct in a way that provides FES with the means to satisfy its obligations over the long-term, may also require FES to restructure debt and other financial obligations with its creditors and/or seek protection under U.S. bankruptcy laws. In the event FES seeks protection under U.S. bankruptcy laws, FENOC will likely seek such protection. Although management is exploring capital and other cost reductions, asset sales, and other options to improve cash flow as well as continuing with efforts to explore legislative or regulatory solutions, these obligations and their impact to liquidity raise substantial doubt about FES’ ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern.

Goodwill

FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. For 2017, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units' goodwill, assessing economic, industry and market considerations in addition to the reporting units' overall financial performance. Key factors used in the assessment include: growth rates, interest rates, expected capital expenditures, utility sector market performance and other market considerations. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary.

New Accounting Pronouncements

Recently Adopted Pronouncements

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

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

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB 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 or in the 2016 Annual Report on Form 10-K based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting. Below is an update to the discussion of pronouncements contained in the 2016 Annual Report on Form 10-K.

ASU 2014-09, "Revenue from Contracts with Customers" (Issued May 2014 and subsequently updated to address implementation questions): For public business entities, the new revenue recognition guidance will be effective for annual and interim reporting periods beginning after December 15, 2017. FirstEnergy will not early adopt the standard. FirstEnergy has evaluated its revenues and expects limited impacts to current revenue recognition practices. FirstEnergy expects to apply the new guidance on a modified retrospective basis and continues to assess the impact on its financial statements and disclosures.

ASU 2016-02, "Leases (Topic 842)" (Issued February 2016): ASU 2016-02 will require organizations that lease assets with lease terms of more than 12 months to recognize assets and liabilities for the rights and obligations created by those leases on their balance sheets. In addition, new qualitative and quantitative disclosures of the amounts, timing, and uncertainty of cash flows arising from leases will be required. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. Lessors and lessees will be required to apply a modified retrospective transition approach, which requires adjusting the accounting for any leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. Any leases that expire before the initial application date will not require any accounting adjustment.

ASU 2017-01, "Business Combinations: Clarifying the Definition of a Business" (Issued January 2017): ASU 2017-01 assists entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. The ASU will be applied prospectively to any transactions occurring within the period of adoption. Early adoption is permitted, including for interim or annual periods in which the financial statements have not been issued or made available for issuance.

ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (Issued March 2017): ASU 2017-07 requires entities to retrospectively (1) disaggregate the current-service-cost component from the other components of net benefit cost (the “other components”) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. In addition, only service costs are eligible for capitalization on a prospective basis. Because the non-service cost components of net benefit cost will no longer be eligible for capitalization after December 31, 2017, FirstEnergy will recognize these components in income as a result of adopting the standard. FirstEnergy is currently evaluating presentation of the Statement of Income and the impact on disclosures as a result of adopting ASU 2017-07. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years.

2. EARNINGS (LOSS) PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. As discussed above, FirstEnergy adopted ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting" beginning January 1, 2017. For the three and nine months ended September 30, 2017, there were no material impacts to the basic or diluted earnings per share due to the new standard.

The following table reconciles basic and diluted earnings (loss) per share of common stock:

(In millions, except per share amounts)	For the Three Months Ended September 30		For the Nine Months Ended September 30	
Reconciliation of Basic and Diluted Earnings (Loss) per Share of Common Stock	2017	2016	2017	2016
Net income (loss)	$396	$380	$775	$(381)
Weighted average number of basic shares outstanding	444	425	444	425
Assumed exercise of dilutive stock options and awards[(1)]	2	2	1	—
Weighted average number of diluted shares outstanding	446	427	445	425
Basic earnings (loss) per share of common stock	$0.89	$0.89	$1.75	$(0.90)
Diluted earnings (loss) per share of common stock	$0.89	$0.89	$1.74	$(0.90)

(1) For both the three and nine months ended September 30, 2017, and the three months ended September 30, 2016, one million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. For the nine months ended September 30, 2016, three million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive as a result of the net loss.

3. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

The components of the consolidated net periodic costs (credits) for pension and OPEB (including amounts capitalized) were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Three Months Ended September 30	2017	2016	2017	2016
	(In millions)			
Service costs	$52	$48	$1	$2
Interest costs	97	99	7	7
Expected return on plan assets	(112)	(100)	(7)	(7)
Amortization of prior service costs (credits)	2	2	(20)	(20)
Net periodic costs (credits)	$39	$49	$(19)	$(18)

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Nine Months Ended September 30	2017	2016	2017	2016
	(In millions)			
Service costs	$156	$144	$3	$4
Interest costs	291	298	21	22
Expected return on plan assets	(336)	(297)	(22)	(23)
Amortization of prior service costs (credits)	6	6	(60)	(60)
Net periodic costs (credits)	$117	$151	$(58)	$(57)

FES' share of the net periodic pension and OPEB costs (credits) were as follows:

	Pension		OPEB	
	2017	2016	2017	2016
	(In millions)			
For the Three Months Ended September 30	$3	$ 6	$(4)	$(4)
For the Nine Months Ended September 30	9	18	(12)	(12)

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Pension and OPEB obligations are allocated to FE's subsidiaries, including FES, employing the plan participants. The net periodic pension and OPEB costs (credits), net of amounts capitalized, recognized in earnings by FirstEnergy and FES were as follows:

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Three Months Ended September 30	2017	2016	2017	2016
	(In millions)			
FirstEnergy	$30	$ 35	$(14)	$(11)
FES	3	5	(4)	(4)

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Nine Months Ended September 30	2017	2016	2017	2016
	(In millions)			
FirstEnergy	$89	$107	$(43)	$(41)
FES	9	17	(12)	(12)

As of September 30, 2017, and December 31, 2016, FES had $866 million of affiliated non-current liabilities related to allocated pension and OPEB mark-to-market costs, of which $570 million was from FENOC.

4. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2017 and 2016, for FirstEnergy are included in the following tables:

FirstEnergy	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of July 1, 2017	$(26)	$ 61	$ 128	$163
Other comprehensive income before reclassifications	—	27	—	27
Amounts reclassified from AOCI	4	(33)	(19)	(48)
Other comprehensive income (loss)	4	(6)	(19)	(21)
Income taxes (benefits) on other comprehensive income (loss)	1	(3)	(7)	(9)
Other comprehensive income (loss), net of tax	3	(3)	(12)	(12)
AOCI Balance as of September 30, 2017	$(23)	$ 58	$ 116	$151
AOCI Balance as of July 1, 2016	$(31)	$ 58	$ 164	$191
Other comprehensive income before reclassifications	—	21	—	21
Amounts reclassified from AOCI	2	(17)	(18)	(33)
Other comprehensive income (loss)	2	4	(18)	(12)
Income taxes (benefits) on other comprehensive income (loss)	—	2	(7)	(5)
Other comprehensive income (loss), net of tax	2	2	(11)	(7)
AOCI Balance as of September 30, 2016	$(29)	$ 60	$ 153	$184

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2017	$(28)	$ 52	$ 150	$174
Other comprehensive income before reclassifications	—	63	—	63
Amounts reclassified from AOCI	8	(55)	(55)	(102)
Other comprehensive income (loss)	8	8	(55)	(39)
Income taxes (benefits) on other comprehensive income (loss)	3	2	(21)	(16)
Other comprehensive income (loss), net of tax	5	6	(34)	(23)
AOCI Balance as of September 30, 2017	$(23)	$ 58	$ 116	$151

AOCI Balance as of January 1, 2016	$(33)	$ 18	$ 186	$171
Other comprehensive income before reclassifications	—	109	—	109
Amounts reclassified from AOCI	6	(42)	(54)	(90)
Other comprehensive income (loss)	6	67	(54)	19
Income taxes (benefits) on other comprehensive income (loss)	2	25	(21)	6
Other comprehensive income (loss), net of tax	4	42	(33)	13
AOCI Balance as of September 30, 2016	$(29)	$ 60	$ 153	$184

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The following amounts were reclassified from AOCI for FirstEnergy in the three and nine months ended September 30, 2017 and 2016:

Reclassifications from AOCI[2]	For the Three Months Ended September 30		For the Nine Months Ended September 30		Affected Line Item in the Consolidated Statements of Income (Loss)
	2017	2016	2017	2016	
	(In millions)				
Gains & losses on cash flow hedges					
Long-term debt	$4	$2	$8	$6	Interest expense
	(1)	—	(3)	(2)	Income taxes
	$3	$2	$5	$4	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(33)	$(17)	$(55)	$(42)	Investment income
	12	7	20	16	Income taxes
	$(21)	$(10)	$(35)	$(26)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(19)	$(18)	$(55)	$(54)	[1]
	7	7	21	21	Income taxes
	$(12)	$(11)	$(34)	$(33)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, "Pension and Other Postemployment Benefits," for additional details.
[2] Amounts in parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2017 and 2016, for FES are included in the following tables:
FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of July 1, 2017	$(9)	$ 62	$ 26	$79
Other comprehensive income before reclassifications	—	27	—	27
Amounts reclassified from AOCI	1	(33)	(3)	(35)
Other comprehensive income (loss)	1	(6)	(3)	(8)
Income tax benefits on other comprehensive income (loss)	—	(2)	(1)	(3)
Other comprehensive income (loss), net of tax	1	(4)	(2)	(5)
AOCI Balance as of September 30, 2017	$(8)	$ 58	$ 24	$74
AOCI Balance as of July 1, 2016	$(10)	$ 50	$ 35	$75
Other comprehensive income before reclassifications	—	22	—	22
Amounts reclassified from AOCI	1	(17)	(3)	(19)
Other comprehensive income (loss)	1	5	(3)	3
Income taxes (benefits) on other comprehensive income (loss)	—	2	(1)	1
Other comprehensive income (loss), net of tax	1	3	(2)	2
AOCI Balance as of September 30, 2016	$(9)	$ 53	$ 33	$77

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2017	$(9)	$ 48	$ 30	$69
Other comprehensive income before reclassifications	—	70	—	70
Amounts reclassified from AOCI	1	(54)	(10)	(63)
Other comprehensive income (loss)	1	16	(10)	7
Income taxes (benefits) on other comprehensive income (loss)	—	6	(4)	2
Other comprehensive income (loss), net of tax	1	10	(6)	5
AOCI Balance as of September 30, 2017	$(8)	$ 58	$ 24	$74

AOCI Balance as of January 1, 2016	$(9)	$ 16	$ 39	$46
Other comprehensive income before reclassifications	—	102	—	102
Amounts reclassified from AOCI	—	(41)	(10)	(51)
Other comprehensive income (loss)	—	61	(10)	51
Income taxes (benefits) on other comprehensive income (loss)	—	24	(4)	20
Other comprehensive income (loss), net of tax	—	37	(6)	31
AOCI Balance as of September 30, 2016	$(9)	$ 53	$ 33	$77

The following amounts were reclassified from AOCI for FES in the three and nine months ended September 30, 2017 and 2016:

Reclassifications from AOCI[2]	For the Three Months Ended September 30		For the Nine Months Ended September 30		Affected Line Item in the Consolidated Statements of Income (Loss)
	2017	2016	2017	2016	
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$1	$1	$1	$—	Other operating expenses
	—	—	—	—	Income taxes (benefits)
	$1	$1	$1	$—	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(33)	$(17)	$(54)	$(41)	Investment income
	11	6	19	15	Income taxes (benefits)
	$(22)	$(11)	$(35)	$(26)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(3)	$(3)	$(10)	$(10)	[1]
	1	1	4	4	Income taxes (benefits)
	$(2)	$(2)	$(6)	$(6)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, "Pension and Other Postemployment Benefits," for additional details.
[2] Amounts in parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

5. INCOME TAXES

FirstEnergy’s and FES’ interim effective tax rates reflect the estimated annual effective tax rates for 2017 and 2016. These tax rates are affected by estimated annual 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.

FirstEnergy’s effective tax rate for the three months ended September 30, 2017 and 2016 was 37.6% and 39.8%, respectively. FirstEnergy’s effective tax rate for the nine months ended September 30, 2017 was 38.3%. For the nine months ended September 30, 2017, the change in the effective tax rate, as compared to the same period for 2016, is primarily due to the impairment of $800 million of goodwill recognized in 2016, of which $433 million was non-deductible for tax purposes. Additionally, $159 million of valuation allowances were recorded in 2016 against state and municipal NOL carryforwards that also impacted the 2016 effective tax rate.

FES’ effective tax rate for the three months ended September 30, 2017 and 2016 was 29.6% and 58.3%, respectively. FES' effective tax rate for the nine months ended September 30, 2017 and 2016 was 48.3% and 1.8%, respectively. For the nine months ended September 30, 2017, the change in the effective tax rate was primarily due to $65 million of valuation allowance recognized in 2016 against state and local NOL carryforwards and the impairment of goodwill also recognized in 2016, of which $23 million was non-deductible for tax purposes.

As of September 30, 2017, it is reasonably possible that approximately $51 million of unrecognized tax benefits may be resolved within the next twelve months as a result of the statute of limitations expiring and expected resolution with respect to certain claims, of which approximately $26 million would affect FirstEnergy's effective tax rate.

In August 2017 and February 2017, the IRS completed its examination of FirstEnergy's 2016 and 2015 federal income tax returns, respectively. The IRS has issued Full Acceptance Letters with no changes or adjustments to FirstEnergy's taxable income in either tax year.

6. VARIABLE INTEREST ENTITIES

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

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

Consolidated VIEs

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

- Ohio Securitization - In September 2012, the Ohio Companies created separate, wholly-owned limited liability company SPEs which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. The SPEs are considered VIEs and each one is consolidated into its applicable utility. As of September 30, 2017 and December 31, 2016, $315 million and $339 million of the phase-in recovery bonds were outstanding, respectively.
- JCP&L Securitization - In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station, which were paid in full at maturity on June 5, 2017. Additionally, in August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding II and are collateralized by its equity and assets, which consist primarily of bondable transition property. As of September 30, 2017 and December 31, 2016, $60 million and $85 million of the transition bonds were outstanding, respectively.
- MP and PE Environmental Funding Companies - The entities issued bonds, the proceeds of which were used to construct environmental control facilities. The limited liability company SPEs own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. Creditors of FirstEnergy, other than the limited liability company SPEs, have no recourse to any assets or revenues of the special purpose limited liability companies. As of September 30, 2017 and December 31, 2016, $383 million and $406 million of the environmental control bonds were outstanding, respectively.

FES does not have any consolidated VIEs.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

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

As discussed in Note 11, "Commitments, Guarantees and Contingencies," FE is the guarantor under Global Holding's $300 million term loan facility. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

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

FirstEnergy maintains 12 long-term PPAs with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities. Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contract that may contain a variable interest during the three months ended September 30, 2017 and 2016 were $29 million and $22 million, respectively, and $82 million and $78 million during the nine months ended September 30, 2017 and 2016, respectively.

- Sale and Leaseback Transactions - FES has obligations that are not included on its Consolidated Balance Sheet related to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement, which are satisfied through operating lease payments. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements. As of September 30, 2017, FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

FES is exposed to losses under the Bruce Mansfield Unit 1 sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses FirstEnergy's net exposure to loss based upon the casualty value provisions as of September 30, 2017:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
	(In millions)		
FirstEnergy[1]	$1,095	$ 873	$ 222

[1] All amounts are associated with FES.

On June 1, 2017, NG completed the purchase of the 2.60% lessor equity interests of the remaining non-affiliated leasehold interests in Beaver Valley Unit 2 for $38 million. In addition, the Beaver Valley Unit 2 leases expired in accordance with their terms on June 1, 2017, resulting in NG being the sole owner of Beaver Valley Unit 2. All debt obligations associated with those sale and leasebacks have been satisfied. Thereafter, OE and TE transferred their NDT assets and related AROs to NG associated with Beaver Valley Unit 2. See Note 9, "Asset Retirement Obligations," for additional information.

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7. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

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

Level 1 - Quoted prices for identical instruments in active market

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

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

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

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

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term PJM auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent PJM auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 8, "Derivative Instruments," for additional information regarding FirstEnergy's FTRs.

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

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of September 30, 2017, from those used as of

December 31, 2016. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the nine months ended September 30, 2017. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	September 30, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,201	$—	$1,201	$—	$1,247	$—	$1,247
Derivative assets - commodity contracts	—	35	—	35	10	200	—	210
Derivative assets - FTRs	—	—	5	5	—	—	7	7
Derivative assets - NUG contracts[1]	—	—	—	—	—	—	1	1
Equity securities[2]	1,045	—	—	1,045	925	—	—	925
Foreign government debt securities	—	92	—	92	—	78	—	78
U.S. government debt securities	—	152	—	152	—	161	—	161
U.S. state debt securities	—	274	—	274	—	246	—	246
Other[3]	399	152	—	551	199	123	—	322
Total assets	$1,444	$1,906	$5	$3,355	$1,134	$2,055	$8	$3,197
Liabilities								
Derivative liabilities - commodity contracts	$—	$(12)	$—	$(12)	$(6)	$(118)	$—	$(124)
Derivative liabilities - FTRs	—	—	(2)	(2)	—	—	(6)	(6)
Derivative liabilities - NUG contracts[1]	—	—	(92)	(92)	—	—	(108)	(108)
Total liabilities	$—	$(12)	$(94)	$(106)	$(6)	$(118)	$(114)	$(238)
Net assets (liabilities)[4]	$1,444	$1,894	$(89)	$3,249	$1,128	$1,937	$(106)	$2,959

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $(13) million and $(3) million as of September 30, 2017 and December 31, 2016, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2017 and December 31, 2016:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2016 Balance	$1	$ (137)	$(136)	$8	$ (13)	$(5)
Unrealized gain (loss)	2	(17)	(15)	(6)	(4)	(10)
Purchases	—	—	—	16	(7)	9
Settlements	(2)	46	44	(11)	18	7
December 31, 2016 Balance	$1	$ (108)	$(107)	$7	$ (6)	$1
Unrealized loss	—	(14)	(14)	—	(2)	(2)
Purchases	—	—	—	5	(2)	3
Settlements	(1)	30	29	(7)	8	1
September 30, 2017 Balance	$—	$ (92)	$(92)	$5	$ (2)	$3

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

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended September 30, 2017:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 3	Model	RTO auction clearing prices	$(5.00) to $4.60	$0.60	Dollars/MWH
NUG Contracts	$ (92)	Model	Generation	400 to 2,322,000	470,000	MWH
			Regional electricity prices	$29.90 to $31.40	$29.90	Dollars/MWH

FES

Recurring Fair Value Measurements	September 30, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$722	$—	$722	$—	$726	$—	$726
Derivative assets - commodity contracts	—	35	—	35	10	200	—	210
Derivative assets - FTRs	—	—	1	1	—	—	4	4
Equity securities(1)	765	—	—	765	634	—	—	634
Foreign government debt securities	—	65	—	65	—	58	—	58
U.S. government debt securities	—	138	—	138	—	48	—	48
U.S. state debt securities	—	21	—	21	—	3	—	3
Other(2)	2	120	—	122	2	81	—	83
Total assets	$767	$1,101	$1	$1,869	$646	$1,116	$4	$1,766
Liabilities								
Derivative liabilities - commodity contracts	$—	$(12)	$—	$(12)	$(6)	$(118)	$—	$(124)
Derivative liabilities - FTRs	—	—	(1)	(1)	—	—	(5)	(5)
Total liabilities	$—	$(12)	$(1)	$(13)	$(6)	$(118)	$(5)	$(129)
Net assets (liabilities)(3)	$767	$1,089	$—	$1,856	$640	$998	$(1)	$1,637

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

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

(3) Excludes $(8) million and $2 million as of September 30, 2017 and December 31, 2016, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2017 and December 31, 2016:

	Derivative Asset	Derivative Liability	Net Asset (Liability)
	(In millions)		
January 1, 2016 Balance	$5	$ (11)	$ (6)
Unrealized loss	(4)	(3)	(7)
Purchases	10	(5)	5
Settlements	(7)	14	7
December 31, 2016 Balance	$4	$ (5)	$ (1)
Unrealized loss	—	(1)	(1)
Purchases	1	(1)	—
Settlements	(4)	6	2
September 30, 2017 Balance	$1	$ (1)	$ —

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended September 30, 2017:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ —	Model	RTO auction clearing prices	($5.00) to $2.60	$0.20	Dollars/MWH

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INVESTMENTS

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

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

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

During the second quarter of 2017, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in the Beaver Valley Unit 2 and the expiration of the leases, OE and TE transferred NDT assets of $189 million associated with their leasehold interests to NG. See Note 9, "Asset Retirement Obligations," for additional information.

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

AFS Securities

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

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT and nuclear fuel disposal trusts as of September 30, 2017 and December 31, 2016:

	September 30, 2017(1)			December 31, 2016(2)		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,701	$ 42	$1,743	$1,735	$ 38	$1,773
FES	942	27	969	847	27	874
Equity securities						
FirstEnergy	$927	$ 118	$1,045	$822	$ 103	$925
FES	675	90	765	564	70	634

(1) Excludes short-term cash investments: FirstEnergy - $100 million; FES - $89 million.
(2) Excludes short-term cash investments: FirstEnergy - $61 million; FES - $44 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three and nine months ended September 30, 2017 and 2016 were as follows:

For the Three Months Ended

September 30, 2017	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$666	$ 93	$ (53)	$(3)	$ 24
FES	397	73	(42)	(3)	15

September 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$337	$ 36	$ (15)	$(3)	$ 27
FES	135	23	(6)	(3)	16

For the Nine Months Ended

September 30, 2017	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,923	$ 276	$ (207)	$(10)	$ 72
FES	834	206	(152)	(10)	44

September 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,361	$ 131	$ (88)	$(13)	$ 75
FES	576	90	(49)	(12)	42

Held-To-Maturity Securities

Unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of September 30, 2017 and December 31, 2016 are immaterial to FirstEnergy. Investments in employee benefit trusts and equity method investments totaling $255 million as of September 30, 2017 and $266 million as of December 31, 2016, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

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

	September 30, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$22,218	$22,994	$19,885	$19,829
FES	2,837	1,620	3,000	1,555

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of September 30, 2017 and December 31, 2016.

8. DERIVATIVE INSTRUMENTS

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

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

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

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

FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

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

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $11 million as of September 30, 2017 and $12 million as of December 31, 2016. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $2 million of net unamortized losses is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $27 million (FES $3 million) and $33 million (FES $3 million) as of September 30, 2017 and December 31, 2016, respectively. Based on current estimates, approximately $8 million of these unamortized losses are expected to be amortized to interest expense during the next twelve months.

Refer to Note 4, "Accumulated Other Comprehensive Income," for reclassifications from AOCI during the three and nine months ended September 30, 2017 and 2016.

As of September 30, 2017 and December 31, 2016, no commodity or interest rate derivatives were designated as cash flow hedges.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. As of September 30, 2017 and December 31, 2016, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $4 million and $10 million as of September 30, 2017 and December 31, 2016, respectively. During the next twelve months, approximately $2 million of unamortized gains are expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $1 million during the three months ended September 30, 2017 and $2 million during the three months ended September 30, 2016. Amortization of unamortized gains included in long-term debt totaled approximately $6 million during the nine months ended September 30, 2017 and $8 million during the nine months ended September 30, 2016.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy’s combustion turbine units. Derivative instruments are not used in quantities greater than forecasted needs.

As of September 30, 2017, FirstEnergy’s net asset position under commodity derivative contracts was $23 million, which related to FES positions. Under these commodity derivative contracts, FES posted less than $1 million of collateral.

Based on commodity derivative contracts held as of September 30, 2017, an increase in commodity prices of 10% would decrease net income by approximately $6 million during the next twelve months.

NUGs

As of September 30, 2017, FirstEnergy's net liability position under NUG contracts was $92 million, representing contracts held at JCP&L, ME and PN. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of September 30, 2017, FirstEnergy's net asset position associated with FTRs was $3 million and FES' net liability was less than $1 million. As of December 31, 2016, FirstEnergy's net asset position associated with FTRs was $1 million and FES' net liability was $1 million. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy’s load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of PJM that have load serving obligations.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to PJM, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by the Utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets	Fair Value September 30, 2017	Fair Value December 31, 2016	Derivative Liabilities	Fair Value September 30, 2017	Fair Value December 31, 2016
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Other		
Commodity Contracts	$ 30	$ 133	Commodity Contracts	$(11)	$ (72)
FTRs	5	7	FTRs	(2)	(6)
	35	140		(13)	(78)
			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs(1)	(92)	(108)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Other		
Commodity Contracts	5	77	Commodity Contracts	(1)	(52)
NUGs(1)	—	1			
	5	78		(93)	(160)
Derivative Assets	$ 40	$ 218	Derivative Liabilities	$(106)	$ (238)

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

FES records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FES' Consolidated Balance Sheets:

Derivative Assets	Fair Value September 30, 2017	Fair Value December 31, 2016	Derivative Liabilities	Fair Value September 30, 2017	Fair Value December 31, 2016
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$30	$ 133	Commodity Contracts	$(11)	$ (72)
FTRs	1	4	FTRs	(1)	(5)
	31	137		(12)	(77)
Deferred Charges and Other Assets - Derivatives			Noncurrent Liabilities - Other		
Commodity Contracts	5	77	Commodity Contracts	(1)	(52)
	5	77		(1)	(52)
Derivative Assets	$36	$ 214	Derivative Liabilities	$(13)	$ (129)

FirstEnergy enters into contracts with counterparties that allow for the offsetting of derivative assets and derivative liabilities under netting arrangements with the same counterparty. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative assets and derivative liabilities on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

September 30, 2017	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$35	$ (9)	$ —	$26
FTRs	5	(2)	—	3
	$40	$ (11)	$ —	$29
Derivative Liabilities				
Commodity contracts	$(12)	$ 9	$ —	$(3)
FTRs	(2)	2	—	—
NUG contracts	(92)	—	—	(92)
	$(106)	$ 11	$ —	$(95)

December 31, 2016	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$210	$ (117)	$ —	$93
FTRs	7	(6)	—	1
NUG contracts	1	—	—	1
	$218	$ (123)	$ —	$95
Derivative Liabilities				
Commodity contracts	$(124)	$ 117	$ 1	$(6)
FTRs	(6)	6	—	—
NUG contracts	(108)	—	—	(108)
	$(238)	$ 123	$ 1	$(114)

The following tables summarize the fair value of derivative assets and derivative liabilities on FES' Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

September 30, 2017	Fair Value	Amounts Not Offset in Consolidated Balance Sheet Derivative Instruments	Cash Collateral Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$35	$ (9)	$ —	$ 26
FTRs	1	(1)	—	—
	$36	$ (10)	$ —	$ 26
Derivative Liabilities				
Commodity contracts	$(12)	$ 9	$ —	$ (3)
FTRs	(1)	1	—	—
	$(13)	$ 10	$ —	$ (3)

December 31, 2016	Fair Value	Amounts Not Offset in Consolidated Balance Sheet Derivative Instruments	Cash Collateral Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$210	$ (117)	$ —	$ 93
FTRs	4	(4)	—	—
	$214	$ (121)	$ —	$ 93
Derivative Liabilities				
Commodity contracts	$(124)	$ 117	$ 1	$ (6)
FTRs	(5)	4	1	—
	$(129)	$ 121	$ 2	$ (6)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of September 30, 2017:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	1	8	(7)	MWH
FTRs	14	—	14	MWH
NUGs	2	—	2	MWH

The following table summarizes the volumes associated with FES' outstanding derivative transactions as of September 30, 2017:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	1	8	(7)	MWH
FTRs	7	—	7	MWH

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The effect of active derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income (Loss) during the three and nine months ended September 30, 2017 and 2016, are summarized in the following tables:

	For the Three Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2017			
Unrealized Loss Recognized in:			
Other Operating Expense	$(11)	$—	$(11)
Realized Gain (Loss) Reclassified to:			
Revenues	$8	$(1)	$7
Purchased Power Expense	(3)	—	(3)
Other Operating Expense	—	(1)	(1)

	For the Three Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$19	$(3)	$16
Realized Gain (Loss) Reclassified to:			
Revenues	$32	$1	$33
Purchased Power Expense	(22)	—	(22)
Other Operating Expense	—	(6)	(6)
Fuel Expense	(2)	—	(2)

	For the Nine Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2017			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(65)	$1	$(64)
Realized Gain (Loss) Reclassified to:			
Revenues	$48	$—	$48
Purchased Power Expense	(14)	—	(14)
Other Operating Expense	—	(14)	(14)

Fuel Expense	5	—	5

	For the Nine Months Ended September 30 Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain Recognized in:			
Other Operating Expense	$2	$ 8	$10
Realized Gain (Loss) Reclassified to:			
Revenues	$162	$ 5	$167
Purchased Power Expense	(105)	—	(105)
Other Operating Expense	—	(28)	(28)
Fuel Expense	(9)	—	(9)

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The effect of active derivative instruments not in a hedging relationship on FES' Consolidated Statements of Income (Loss) during the three and nine months ended September 30, 2017 and 2016, are summarized in the following tables:

	For the Three Months Ended September 30		
	Commodity Contracts	FTRs	Total
2017	(In millions)		
Unrealized Loss Recognized in:			
Other Operating Expense	$(11)	$—	$(11)
Realized Gain (Loss) Reclassified to:			
Revenues	$8	$(1)	$7
Purchased Power Expense	(3)	—	(3)
Other Operating Expense	—	(1)	(1)

	For the Three Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$19	$(3)	$16
Realized Gain (Loss) Reclassified to:			
Revenues	$32	$1	$33
Purchased Power Expense	(22)	—	(22)
Other Operating Expense	—	(6)	(6)

	For the Nine Months Ended September 30		
	Commodity Contracts	FTRs	Total
2017	(In millions)		
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(65)	$1	$(64)
Realized Gain (Loss) Reclassified to:			
Revenues	$48	$—	$48
Purchased Power Expense	(14)	—	(14)
Other Operating Expense	—	(14)	(14)

	For the Nine Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain Recognized in:			
Other Operating Expense	$2	$ 8	$10
Realized Gain (Loss) Reclassified to:			
Revenues	$162	$ 5	$167
Purchased Power Expense	(105)	—	(105)
Other Operating Expense	—	(28)	(28)

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during the three and nine months ended September 30, 2017 and 2016. Changes in the value of these instruments are deferred for future recovery from (or credit to) customers:

	For the Three Months Ended September 30		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of July 1, 2017	$(98)	$ 3	$(95)
Unrealized loss	(4)	—	(4)
Settlements	10	—	10
Outstanding net asset (liability) as of September 30, 2017	$(92)	$ 3	$(89)
Outstanding net asset (liability) as of July 1, 2016	$(124)	$ 4	$(120)
Unrealized loss	(6)	—	(6)
Settlements	12	—	12
Outstanding net asset (liability) as of September 30, 2016	$(118)	$ 4	$(114)

	For the Nine Months Ended September 30		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2017	$(107)	$ 2	$(105)
Unrealized loss	(14)	(1)	(15)
Purchases	—	3	3
Settlements	29	(1)	28
Outstanding net asset (liability) as of September 30, 2017	$(92)	$ 3	$(89)
Outstanding net asset (liability) as of January 1, 2016	$(136)	$ 1	$(135)
Unrealized loss	(17)	(1)	(18)
Purchases	—	4	4
Settlements	35	—	35
Outstanding net asset (liability) as of September 30, 2016	$(118)	$ 4	$(114)

9. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation. FirstEnergy and FES use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities, which aggregate to approximately $800 million and $713 million, as of September 30, 2017 and December 31, 2016, respectively.

During the second quarter of 2017, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in the Beaver Valley Unit 2 sale leaseback and the expiration of the leases, OE and TE transferred an ARO of $49 million and NDT assets associated with their leasehold interests to NG, with the difference of $73 million credited to the common stock of FES.

During the second quarter of 2016, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in the Perry Unit 1 sale leaseback, OE transferred the ARO and related NDT assets associated with the leasehold interest to NG, with the difference of $28 million credited to the common stock of FES.

10. REGULATORY MATTERS

STATE REGULATION

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

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third-party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption and demand and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the goal of 0.97% savings achieved under PE's current plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. The costs of the 2015-2017 plan are expected to be approximately $70 million, of which approximately $56 million was incurred through September 30, 2017. PE filed its 2018-2020 EmPOWER plan on August 31, 2017. The 2018-2020 plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. The MDPSC will consider the 2018-2020 plan in hearings scheduled to begin on October 25, 2017, with a decision expected by December 31, 2017. PE recovers program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE.

On February 27, 2013, the MDPSC issued an order requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 2013 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 2013 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting, as well as the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the Maryland utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On September 26, 2016, the MDPSC initiated a new proceeding to consider an array of issues relating to electric distribution system design, including matters relating to electric vehicles, distributed energy resources, advanced metering infrastructure, energy storage, system planning, rate design, and impacts on low-income customers. Initial comments in the proceeding were filed on October 28, 2016, and the MDPSC held an initial hearing on the matter on December 8-9, 2016. On January 31, 2017, the MDPSC issued a notice establishing five working groups to address these issues over the following eighteen months, and also directed the retention of an outside consultant to prepare a report on costs and benefits of distributed solar generation in Maryland.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third-party EGS and for customers of third-party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended to improve service and benefit customers by supporting equipment maintenance, tree trimming, and inspections of lines, poles and substations, while also compensating for other business and operating expenses. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L's 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases, the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the generic CTA proceeding to the Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On October 20, 2017, the NJBPU directed its staff to begin a formal rulemaking process to modify its CTA methodology.

OHIO

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

ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024. Other material terms of ESP IV include: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016 and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates (which filing was made on April 3, 2017 and remains pending).

Several parties, including the Ohio Companies, filed applications for rehearing regarding the Ohio Companies' ESP IV with the PUCO. The Ohio Companies' application for rehearing challenged, among other things, the PUCO's failure to adopt the Ohio Companies' suggested modifications to Rider DMR. The Ohio Companies had previously suggested that a properly designed Rider DMR would be valued at $558 million annually for eight years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio. Other parties' applications for rehearing argued, among other things, that the PUCO's adoption of Rider DMR is not supported by law or sufficient evidence. On August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies' challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO's August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the Ohio Manufacturer's Association Energy Group filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. For additional information, see "FERC Matters - Ohio ESP IV PPA" below.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. Starting in 2017, ORC 4928.66 requires the energy savings benchmark to increase by 1% and the peak demand reduction benchmark to increase by 0.75% annually thereafter through 2020 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. On April 15, 2016, the Ohio Companies filed an application for approval of their three-year energy efficiency portfolio plans for the period from January 1, 2017 through December 31, 2019. The plans as proposed comply with benchmarks contemplated by ORC 4928.66 and provisions of the ESP IV, and include a portfolio of energy efficiency programs targeted to a variety of customer segments, including residential customers, low income customers, small commercial customers, large commercial and industrial customers and governmental entities. On December 9, 2016, the Ohio Companies filed a Stipulation and Recommendation with several parties that contained changes to the plan and a decrease in the plan costs. The Ohio Companies anticipate the cost of the plans will be approximately $268 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies' existing rate mechanisms. The hearings were held in January 2017.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, except that in 2014 SB310 froze 2015 and 2016 at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. Oral argument on this matter was held on June 21, 2017.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers. On January 13, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing. On March 29, 2017, the PUCO issued a Second Entry on Rehearing that granted, in part, the applications for rehearing filed by FES and other parties, finding that the PUCO's guidelines regarding fixed-price contracts should not apply to large mercantile customers. This finding changes the original order, which applied the guidelines to all customers, including mercantile customers. The PUCO also reaffirmed several provisions of the original order, including that the fixed-price guidelines only apply on a going-forward basis and not to existing contracts and that regulatory-out clauses in contracts are permissible.

PENNSYLVANIA

The Pennsylvania Companies operate under DSPs for the June 1, 2017 through May 31, 2019 delivery period, which provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the DSPs, the supply will be provided by wholesale suppliers through a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. The DSPs include modifications to the Pennsylvania Companies’ POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

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

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies’ historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, with expected costs up to $390 million, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order with full recovery through the reconcilable EE&C riders.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the five-year period of 2016 to 2020, as modified, are: WP $88.3 million; PN $60.0 million; Penn $58.9 million; and ME $51.6 million.

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

WEST VIRGINIA

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

On September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. On October 6, 2017, MP and PE proposed an annual decrease in their EE&C rates, effective January 1, 2018, which is not expected to be material to FirstEnergy.

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

On December 30, 2015, MP and PE filed an IRP with the WVPSC identifying a capacity shortfall starting in 2016 and exceeding 700 MWs by 2020 and 850 MWs by 2027. On June 3, 2016, the WVPSC accepted the IRP. On December 16, 2016, MP issued an RFP to address its generation shortfall, along with issuing a second RFP to sell its interest in Bath County. Bids were received by an independent evaluator in February 2017 for both RFPs. AE Supply was the winning bidder of the RFP to address MP’s generation shortfall and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire AE Supply’s Pleasants Power Station (1,300 MW) for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals. In addition, on March 7, 2017, MP and PE filed an application with the WVPSC and MP and AE Supply filed an application with FERC requesting authorization for such purchase. The WVPSC held an evidentiary hearing commencing on September 26, 2017, and public hearings were held on September 6, 11, and 12, 2017. An order is anticipated by early 2018. On June 27, 2017, FERC issued a deficiency letter requesting additional information to facilitate FERC's review of the transaction. MP responded to the deficiency letter on July 18, 2017, and to related protests and comments on August 28, 2017. The applications remain pending before the WVPSC and FERC, respectively. With respect to the Bath County RFP, MP does not plan to move forward with that sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

On September 1, 2017, MP and PE filed with the WVPSC for a reconciliation of their VMS to confirm that rate recovery matches VMP costs and for a regular review of that program. MP and PE proposed a $15 million annual decrease in VMS rates effective January 1, 2018, and an additional $15 million decrease in rates for 2019. This is an overall decrease in total revenue and average rates of 1%.

RELIABILITY MATTERS

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

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

FERC MATTERS

Ohio ESP IV PPA

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

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

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for certain transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole.

The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. On June 15, 2016, various parties, including ATSI and the Utilities, filed a settlement agreement at FERC agreeing to apply a combined usage based/socialization approach to cost allocation for charges to transmission customers in the PJM Region for transmission projects operating at or above 500 kV. Certain other parties in the proceeding did not agree to the settlement and filed protests to the settlement seeking, among other issues, to strike certain of the evidence advanced by FirstEnergy and certain of the other settling parties in support of the settlement, as well as provided further comments in opposition to the settlement. FirstEnergy and certain of the other parties responded to such opposition. The settlement is pending before FERC.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On March 17, 2016, FERC denied FirstEnergy's request for rehearing of FERC's earlier order rejecting the settlement agreement and affirmed its prior ruling that ATSI must submit the cost/benefit analysis.

Separately, ATSI resolved a dispute regarding responsibility for certain costs for the “Michigan Thumb” transmission project. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which FERC denied on May 19, 2016. The MISO TOs subsequently filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened and participated in the proceedings on behalf of ATSI, the Ohio Companies and PP. On June 21, 2017, the Sixth Circuit issued its decision denying the MISO TOs' appeal request. September 19, 2017 was the deadline for MISO and the MISO TOs to seek review by the U.S. Supreme Court. They did not file for review, effectively resolving the dispute over the "Michigan Thumb" transmission project. On a related issue, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

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

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

MAIT Transmission Formula Rate

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

JCP&L Transmission Formula Rate

On October 28, 2016, after withdrawing its request to the NJBPU to transfer its transmission assets to MAIT, JCP&L submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective January 1, 2017. A group of intervenors, including the NJBPU and New Jersey Division of Rate Counsel, filed a protest of the proposed JCP&L transmission rate. Among other things, the protest asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. On

March 10, 2017, FERC issued an order accepting the JCP&L formula transmission rate for filing, suspending it for five months, and establishing hearing and settlement judge procedures. On April 10, 2017, JCP&L requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. JCP&L’s rates went into effect on June 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. The settlement process is ongoing.

DOE NOPR: Grid Reliability and Resilience Pricing, FERC Docket No. RM18-1

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

FERC is not required to adopt the rules proposed by the DOE in the NOPR. FERC could take other actions as it deems fit pursuant to its statutory authority. On October 2, 2017, FERC established a docket and requested comments on the NOPR. On October 23, 2017, FESC and certain of its affiliates submitted comments. Reply comments are due November 7, 2017. At this time, we are uncertain as to the potential impact that final rules adopted by FERC, if any, would have on FES and our strategic options, and the timing thereof, with respect to the competitive business.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017 and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers commented on the compliance filing, alleging inaccuracies in and lack of transparency of data and information in the compliance filing, and requested that PATH be directed to recalculate the refund provided in the filing. PATH responded to these comments in a filing that was submitted on May 22, 2017. On July 27, 2017, FERC Staff issued a letter to PATH requesting additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH filed its response on September 27, 2017. FERC orders on PATH's requests for rehearing and compliance filing remain pending.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and its subsidiaries, Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 23, 2016, FESC, on behalf of its affiliates with market-based rate authority, submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. On July 27, 2017, FERC accepted the triennial filing as submitted.

11. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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 September 30, 2017, FirstEnergy's outstanding guarantees and other assurances aggregated approximately $3.3 billion, consisting of parental guarantees ($649 million), subsidiaries' guarantees ($1.9 billion), other guarantees ($300 million) and other assurances ($457 million).

Of the aggregate amount, substantially all relates to guarantees of wholly-owned consolidated entities of FirstEnergy. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG and NG would have claims against each of FES, FG and NG, regardless of whether their primary obligor is FES, FG or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on CES' power portfolio exposure as of September 30, 2017, FES has posted collateral of $128 million and AE Supply has posted collateral of $2 million. The Regulated Distribution Segment has posted collateral of $3 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of September 30, 2017.

Potential Collateral Obligations	FES	AE Supply	Regulated	FE Corp	Total
		(In millions)			
Contractual Obligations for Additional Collateral					
At Current Credit Rating	$6	$ 2	$ —	$—	$8
Upon Further Downgrade	—	—	42	—	42
Surety Bonds (Collateralized Amount)[1]	48	24	105	185	362
Total Exposure from Contractual Obligations	$54	$ 26	$ 147	$185	$412

[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 $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of September 30, 2017, FES has $2 million of collateral posted with its affiliates.

OTHER COMMITMENTS AND CONTINGENCIES

FE is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the facility.

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

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition.

Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA’s regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Various states and other stakeholders appealed the CSAPR update rule to the D.C. Circuit in November and December 2016. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, EPA’s reconsideration of the CSAPR update rule and how EPA and the states ultimately implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's and FES' operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but the EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. The EPA missed the October 1, 2017 deadline and has not yet promulgated the attainment designations. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State Delaware's CAA Section 126 petition by six months to April 7, 2017 but has not taken any further action. In November 2016, the State of Maryland filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 36 EGUs, including Harrison Units 1, 2 and 3, Mansfield Unit 1 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition seeks NOx emission rate limits for the 36 EGUs by May 1, 2017. On January 3, 2017, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to July 15, 2017 but has not taken any further action. On September 27, 2017 and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the U.S. District Court for the District of Maryland seeking an order that EPA either approve or deny the CAA Section 126 petition of November 16, 2016. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

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

On August 3, 2015, FG, a wholly owned subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure event that excuses FG’s performance under its coal transportation contract with these parties. Specifically, the dispute arose from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, all plants covered by this contract were deactivated by April 16, 2015. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG’s declaration of a force majeure under the contract is not valid and seeking damages under the contract through 2025. On May 31, 2016, the parties agreed to a stipulation that if FG’s force majeure defense is determined to be wholly or partially invalid, liquidated damages are the sole remedy available to BNSF and CSX. The arbitration panel consolidated the claims and held a hearing in November and December 2016. On April 12, 2017, the arbitration panel ruled on liability in favor of BNSF and CSX. In the liability award, the panel found, among other things, that FG’s demand for declaratory judgment that force majeure excused FG’s performance was denied, that FG breached and repudiated the coal transportation contract and that the panel retains jurisdiction of claims for liquidated damages for the years 2015-2025. On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to this consolidated proceeding on the terms and conditions set forth below. Pursuant to the settlement agreement, FG will pay CSX and BNSF an aggregate amount equal to $109 million which is payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provides that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. Further, FE and FG, and CSX and BNSF, agreed to release, waive and discharge each other from any further obligations under the claims covered by the settlement agreement upon payment in full of the settlement amount. Until such time, CSX and BNSF will retain the claims covered by the settlement agreement and in the event of a bankruptcy proceeding with respect to FG, to the extent the remaining settlement payments are not paid in full by FG or FE, CSX and BNSF shall be entitled to seek damages for such claims in an amount to be determined by the arbitration panel or otherwise agreed by the parties.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS, which are the counterparties to the coal transportation contract covering the delivery of 2.5 million tons annually through 2025, for FG's coal-fired Bay Shore Units 2-4, deactivated on September 1, 2012, as a result of the EPA's MATS and for FG's W.H. Sammis generating station. The demand for arbitration was submitted to the AAA office in Washington, D.C. against FG alleging, among other things, that FG breached the agreement in 2015 and 2016 and repudiated the agreement for 2017-2025. The counterparties are seeking, among other things, damages, including lost profits through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. The arbitration hearing is scheduled for June 2018. The parties have exchanged settlement proposals to resolve all claims related to this proceeding and all remaining claims. FirstEnergy and FES recorded a pre-tax charge of $55 million in the first quarter of 2017 based on an estimated settlement. If the dispute with BNSF and NS is not settled, the amount of damages owed to BNSF and NS could be materially higher and may cause FES to seek protection under U.S. bankruptcy laws. Absent a settlement, FG intends to vigorously assert its position in this arbitration proceeding, and if it were ultimately determined that the force majeure provisions or other defenses do not excuse the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

As to a specific coal supply agreement, AE Supply, the party thereto, asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, on January 15, 2015, Tunnel Ridge, LLC, the coal supplier, commenced litigation in the Court of Common Pleas of Allegheny County, Pennsylvania alleging AE Supply did not have sufficient justification to terminate the agreement and seeking damages for the difference between the market and contract price of the coal, or lost profits plus incidental damages. AE Supply filed an answer denying any liability related to the termination. On May 1, 2017, the complaint was amended to add FE, FES and FG, although not parties to the underlying contract, as defendants and to seek additional damages based on new claims of fraud, unjust enrichment, promissory estoppel and alter ego. On June 27, 2017, after oral argument, defendants' preliminary objections to the amended complaint were denied. FE, FES, FG and AE Supply believe the merits of this case are distinguishable from the rail arbitration proceedings above based on the contract terms and other elements of the case. There were approximately 5.5 million tons remaining under the contract for delivery. This matter is in the discovery phase of litigation and no trial date has been established. FE, FES, FG and AE Supply dispute the allegations and intend to vigorously defend the merits of the lawsuit. At this time, FE, FES, FG and AE Supply cannot estimate the loss or range of loss regarding the ongoing litigation with respect to this agreement. Damages, if any, are yet to be determined, but an adverse outcome could be material.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, March 27, 2013 and October 18, 2016, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

FirstEnergy has established a goal to reduce CO_2 emissions by 90% below 2005 levels by 2045. There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

The EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act” in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. The EPA released its final CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA’s state specific CO_2 emission rate goals. The EPA’s CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2016, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. On March 28, 2017, an executive order, entitled "Promoting Energy Independence and Economic Growth," instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be material.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide GHG emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement was ratified by the requisite number of countries (i.e., at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require material capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

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

On September 30, 2015, the EPA finalized new, more stringent effluent limits for the Steam Electric Power Generating category (40 CFR Part 423) for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, any changes in timing and closure plan requirements in the future, including changes resulting from the strategic review at CES, could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The CCRs from the Bruce Mansfield plant are being beneficially reused with the majority used for reclamation of a site owned by the Marshall County Coal Company in Moundsville, W. Va. and the remainder recycled into drywall by National Gypsum. These beneficial reuse options should be sufficient for ongoing plant operations, however, the Bruce Mansfield plant is pursuing other options. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On September 14, 2017, the Sierra Club's Notices of Appeal before the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility were resolved through a Consent Adjudication between FG, PA DEP and the Sierra Club requiring operational changes, which is subject to a thirty-day comment period with final approval expected in November 2017.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of September 30, 2017 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $131 million have been accrued through September 30, 2017. Included in the total are accrued liabilities of approximately $84 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of September 30, 2017, FirstEnergy had approximately $2.6 billion (FES $1.8 billion) invested in external trusts to be used for the decommissioning and environmental remediation of its nuclear generating facilities. The values of FirstEnergy's NDTs also fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs.

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

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. Although a majority of the necessary modifications and evaluations at FirstEnergy’s nuclear facilities have been completed, some still remain subject to regulatory review or approval.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units, have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. So long as FES remains in the unregulated companies’ money pool, the $500 million secured line of credit with FE discussed in Note 1, "Organization and Basis of Presentation - Going Concern at FES" above provides FES the needed liquidity in order for FES to satisfy its nuclear support obligations to NG.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 10, "Regulatory Matters" of the Combined Notes to Consolidated Financial Statements.

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

12. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG, a 100% owned subsidiary of FES, completed a sale and leaseback transaction for a 93.83% undivided interest in Bruce Mansfield Unit 1. FG's parent company, FES, has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FG or its parent company, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the three and nine months ended September 30, 2017 and 2016, Condensed Consolidating Balance Sheets as of September 30, 2017 and December 31, 2016, and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2017 and 2016, for the parent and guarantor and non-guarantor subsidiaries are presented below. These statements are provided as FG's parent company fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by the parent company using the equity method. Results of operations for FG and NG are, therefore, reflected in their parent company's investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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

For the Three Months Ended September 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$741	$231	$292	$ (521)	$ 743
OPERATING EXPENSES:					
Fuel	—	108	57	—	165
Purchased power from affiliates	520	—	1	(521)	—
Purchased power from non-affiliates	152	—	—	—	152
Other operating expenses	70	62	147	12	291
Provision for depreciation	3	8	18	(1)	28
General taxes	4	3	(2)	—	5
Total operating expenses	749	181	221	(510)	641
OPERATING INCOME (LOSS)	(8)	50	71	(11)	102
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	106	11	43	(121)	39
Miscellaneous income	1	—	—	—	1
Interest expense — affiliates	(20)	(3)	1	16	(6)
Interest expense — other	(12)	(25)	(11)	14	(34)
Capitalized interest	—	—	6	—	6
Total other income (expense)	75	(17)	39	(91)	6
INCOME BEFORE INCOME TAXES (BENEFITS)	67	33	110	(102)	108
INCOME TAXES (BENEFITS)	(9)	6	34	1	32
NET INCOME	$76	$27	$76	$ (103)	$ 76
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME	$76	$27	$76	$ (103)	$ 76
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(3)	(3)	—	3	(3)
Amortized gains on derivative hedges	1	—	—	—	1
Change in unrealized gains on available-for-sale securities	(6)	—	(6)	6	(6)
Other comprehensive loss	(8)	(3)	(6)	9	(8)
Income tax benefits on other comprehensive loss	(3)	(1)	(2)	3	(3)
Other comprehensive loss, net of tax	(5)	(2)	(4)	6	(5)
COMPREHENSIVE INCOME	$71	$25	$72	$ (97)	$ 71

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

For the Nine Months Ended September 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$2,338	$941	$988	$ (1,869)	$ 2,398
OPERATING EXPENSES:					
Fuel	—	312	151	—	463
Purchased power from affiliates	1,994	—	77	(1,869)	202
Purchased power from non-affiliates	468	—	—	—	468
Other operating expenses	247	345	467	36	1,095
Provision for depreciation	9	24	49	(2)	80
General taxes	15	16	13	—	44
Total operating expenses	2,733	697	757	(1,835)	2,352
OPERATING INCOME (LOSS)	(395)	244	231	(34)	46
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income (loss) from equity investees	335	31	91	(383)	74
Miscellaneous income	1	—	5	—	6
Interest expense — affiliates	(58)	(9)	(1)	55	(13)
Interest expense — other	(35)	(78)	(33)	42	(104)
Capitalized interest	—	1	19	—	20
Total other income (expense)	243	(55)	81	(286)	(17)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(152)	189	312	(320)	29
INCOME TAXES (BENEFITS)	(167)	66	112	3	14
NET INCOME	$15	$123	$200	$ (323)	$ 15
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$15	$123	$200	$ (323)	$ 15
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(10)	(10)	—	10	(10)
Amortized gains on derivative hedges	1	—	—	—	1
Change in unrealized gains on available-for-sale securities	16	—	16	(16)	16
Other comprehensive income (loss)	7	(10)	16	(6)	7
Income taxes (benefits) on other comprehensive income (loss)	2	(4)	6	(2)	2
Other comprehensive income (loss), net of tax	5	(6)	10	(4)	5
COMPREHENSIVE INCOME	$20	$117	$210	$ (327)	$ 20

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

For the Three Months Ended September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,065	$494	$400	$ (859)	$ 1,100
OPERATING EXPENSES:					
Fuel	—	149	53	—	202
Purchased power from affiliates	1,011	—	39	(859)	191
Purchased power from non-affiliates	186	—	—	—	186
Other operating expenses	95	61	149	11	316
Provision for depreciation	4	28	51	—	83
General taxes	8	7	6	—	21
Total operating expenses	1,304	245	298	(848)	999
OPERATING INCOME (LOSS)	(239)	249	102	(11)	101
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	224	8	28	(236)	24
Miscellaneous income	—	1	—	—	1
Interest expense — affiliates	(13)	(3)	(2)	15	(3)
Interest expense — other	(14)	(27)	(9)	14	(36)
Capitalized interest	—	3	6	—	9
Total other income (expense)	197	(18)	23	(207)	(5)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(42)	231	125	(218)	96
INCOME TAXES (BENEFITS)	(82)	87	49	2	56
NET INCOME	$40	$144	$76	$ (220)	$ 40
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$40	$144	$76	$ (220)	$ 40
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(3)	(3)	—	3	(3)
Amortized gains on derivative hedges	1	—	—	—	1
Change in unrealized gains on available for sale securities	5	—	5	(5)	5
Other comprehensive income (loss)	3	(3)	5	(2)	3
Income taxes (benefits) on other comprehensive income (loss)	1	(1)	2	(1)	1
Other comprehensive income (loss), net of tax	2	(2)	3	(1)	2
COMPREHENSIVE INCOME	$42	$142	$79	$ (221)	$ 42

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

For the Nine Months Ended September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$3,281	$1,309	$1,404	$ (2,593)	$ 3,401
OPERATING EXPENSES:					
Fuel	—	449	146	—	595
Purchased power from affiliates	2,888	—	145	(2,593)	440
Purchased power from non-affiliates	829	—	—	—	829
Other operating expenses	218	220	450	37	925
Provision for depreciation	10	91	151	(2)	250
General taxes	23	23	20	—	66
Impairment of assets	23	517	—	—	540
Total operating expenses	3,991	1,300	912	(2,558)	3,645
OPERATING INCOME (LOSS)	(710)	9	492	(35)	(244)
OTHER INCOME (EXPENSE):					
Investment income, including net income (loss) from equity investees	310	21	67	(342)	56
Miscellaneous income	3	1	—	—	4
Interest expense — affiliates	(34)	(7)	(4)	39	(6)
Interest expense — other	(40)	(79)	(33)	43	(109)
Capitalized interest	—	7	20	—	27
Total other income (expense)	239	(57)	50	(260)	(28)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(471)	(48)	542	(295)	(272)
INCOME TAXES (BENEFITS)	(204)	(1)	196	4	(5)
NET INCOME (LOSS)	$(267)	$(47)	$346	$ (299)	$ (267)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(267)	$(47)	$346	$ (299)	$ (267)
OTHER COMPREHENSIVE INCOME (LOSS)					
Pension and OPEB prior service costs	(10)	(10)	—	10	(10)
Amortized gains on derivative hedges	—	—	—	—	—
Change in unrealized gains on available-for-sale securities	61	—	60	(60)	61
Other comprehensive income (loss)	51	(10)	60	(50)	51
Income taxes (benefits) on other comprehensive income (loss)	20	(4)	23	(19)	20
Other comprehensive income (loss), net of tax	31	(6)	37	(31)	31

COMPREHENSIVE INCOME (LOSS)	$(236)	$(53)	$383	$ (330)	$ (236)

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of September 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$ —	$ 2
Receivables-					
Customers	171	—	—	—	171
Affiliated companies	194	175	193	(235)	327
Other	9	4	—	—	13
Notes receivable from affiliated companies	364	1,765	1,481	(3,610)	—
Materials and supplies	34	147	82	—	263
Derivatives	31	—	—	—	31
Collateral	101	25	—	—	126
Prepaid taxes and other	12	16	1	—	29
	916	2,134	1,757	(3,845)	962
PROPERTY, PLANT AND EQUIPMENT:					
In service	121	2,587	5,016	(281)	7,443
Less — Accumulated provision for depreciation	61	1,942	4,309	(189)	6,123
	60	645	707	(92)	1,320
Construction work in progress	2	45	241	—	288
	62	690	948	(92)	1,608
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,823	—	1,823
Investment in affiliated companies	3,347	—	—	(3,347)	—
Other	—	9	—	—	9
	3,347	9	1,823	(3,347)	1,832
DEFERRED CHARGES AND OTHER ASSETS:					
Property taxes	—	2	4	—	6
Accumulated deferred income tax benefits	428	1,212	690	(273)	2,057
Derivatives	5	—	—	—	5
Other	31	328	—	10	369
	464	1,542	694	(263)	2,437
	$4,789	$4,375	$5,222	$ (7,547)	$ 6,839
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$180	$114	$ (27)	$ 267
Short-term borrowings - affiliated companies	3,299	497	—	(3,610)	186
Accounts payable-					
Affiliated companies	329	87	143	(329)	230
Other	11	87	—	—	98
Accrued taxes	16	12	19	(15)	32
Derivatives	10	2	—	—	12
Other	28	92	14	33	167
	3,693	957	290	(3,948)	992

CAPITALIZATION:					
Total equity	328	946	2,301	(3,247)	328
Long-term debt and other long-term obligations	691	1,941	1,006	(1,079)	2,559
	1,019	2,887	3,307	(4,326)	2,887
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	732	732
Accumulated deferred income taxes	5	—	—	(5)	—
Retirement benefits	26	181	—	—	207
Asset retirement obligations	—	187	801	—	988
Other	46	163	824	—	1,033
	77	531	1,625	727	2,960
	$4,789	$4,375	$5,222	$ (7,547)	$ 6,839

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$ —	$ 2
Receivables-					
Customers	213	—	—	—	213
Affiliated companies	332	315	417	(612)	452
Other	17	2	8	—	27
Notes receivable from affiliated companies	501	1,585	1,294	(3,351)	29
Materials and supplies	45	142	80	—	267
Derivatives	137	—	—	—	137
Collateral	157	—	—	—	157
Prepaid taxes and other	38	24	1	—	63
	1,440	2,070	1,800	(3,963)	1,347
PROPERTY, PLANT AND EQUIPMENT:					
In service	120	2,524	4,703	(290)	7,057
Less — Accumulated provision for depreciation	52	1,920	4,144	(187)	5,929
	68	604	559	(103)	1,128
Construction work in progress	2	67	358	—	427
	70	671	917	(103)	1,555
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,552	—	1,552
Investment in affiliated companies	2,923	—	—	(2,923)	—
Other	—	9	1	—	10
	2,923	9	1,553	(2,923)	1,562
DEFERRED CHARGES AND OTHER ASSETS:					
Property taxes	—	12	28	—	40
Accumulated deferred income tax benefits	395	1,271	883	(270)	2,279
Derivatives	77	—	—	—	77
Other	33	327	—	21	381
	505	1,610	911	(249)	2,777
	$4,938	$4,360	$5,181	$ (7,238)	$ 7,241
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$200	$5	$ (26)	$ 179
Short-term borrowings - affiliated companies	2,969	483	—	(3,351)	101
Accounts payable-					
Affiliated companies	743	107	406	(706)	550
Other	17	93	—	—	110
Accrued taxes	50	48	61	(16)	143
Derivatives	71	6	—	—	77
Other	56	54	10	36	156
	3,906	991	482	(4,063)	1,316

CAPITALIZATION:					
Total equity	218	828	2,006	(2,834)	218
Long-term debt and other long-term obligations	691	2,093	1,120	(1,091)	2,813
	909	2,921	3,126	(3,925)	3,031
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	757	757
Accumulated deferred income taxes	4	3	—	(7)	—
Retirement benefits	25	172	—	—	197
Asset retirement obligations	—	188	713	—	901
Other	94	85	860	—	1,039
	123	448	1,573	750	2,894
	$4,938	$4,360	$5,181	$ (7,238)	$ 7,241

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Nine Months Ended September 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH (USED FOR) PROVIDED FROM OPERATING ACTIVITIES	$(463)	$387	$547	$ (13)	$ 458
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	330	14	—	(259)	85
Redemptions and Repayments-					
Long-term debt	—	(171)	(5)	13	(163)
Other	—	(5)	—	—	(5)
Net cash (used for) provided from financing activities	330	(162)	(5)	(246)	(83)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(1)	(46)	(154)	—	(201)
Nuclear fuel	—	—	(156)	—	(156)
Sales of investment securities held in trusts	—	—	834	—	834
Purchases of investment securities held in trusts	—	—	(878)	—	(878)
Loans to affiliated companies, net	137	(179)	(188)	259	29
Other	(3)	—	—	—	(3)
Net cash (used for) provided from investing activities	133	(225)	(542)	259	(375)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$—	$2	$—	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Nine Months Ended September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH (USED FOR) PROVIDED FROM OPERATING ACTIVITIES	$(605)	$402	$820	$ (12)	$ 605
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	186	285	—	471
Short-term borrowings, net	701	92	—	(692)	101
Redemptions and Repayments-					
Long-term debt	—	(211)	(304)	12	(503)
Other	—	(6)	(2)	—	(8)
Net cash (used for) provided from financing activities	701	61	(21)	(680)	61
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(28)	(171)	(233)	—	(432)
Nuclear fuel	—	—	(195)	—	(195)
Sales of investment securities held in trusts	—	—	576	—	576
Purchases of investment securities held in trusts	—	—	(619)	—	(619)
Loans to affiliated companies, net	(87)	(292)	(328)	692	(15)
Other	19	—	—	—	19
Net cash (used for) provided from investing activities	(96)	(463)	(799)	692	(666)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$—	$2	$—	$ —	$ 2

13. SEGMENT INFORMATION

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

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

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, MAIT (effective January 31, 2017) and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP). The segment's revenues are primarily derived from forward-looking rates at ATSI and TrAIL, as well as stated transmission rates at certain of FirstEnergy’s utilities. As discussed in Note 10, "Regulatory Matters - FERC Matters" above, MAIT and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. In March 2017, FERC approved JCP&L's and MAIT's forward-looking formula rate with effective dates of June 1, 2017, and July 1, 2017, respectively, both subject to refund pending the outcome of settlement and hearing proceedings and a final order by FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under forward-looking rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The CES segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. As of September 30, 2017, this business segment controlled 13,162 MWs of electric generating capacity, including, as discussed in Note 14, "Asset Impairments," 1,615 MWs of natural gas and hydroelectric generating capacity subject to an asset purchase agreement with a subsidiary of LS Power and the 1,300 MW Pleasants power station subject to an asset purchase agreement with MP resulting from MP's RFP process to address its generation shortfall, as discussed in Note 10, "Regulatory Matters - State Regulation - West Virginia." The CES segment’s operating results are primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs and capacity costs charged by PJM to deliver energy to the segment’s customers, as well as other operating and maintenance costs, including costs incurred by FENOC.

Corporate support not charged to FE's subsidiaries, interest expense on stand-alone holding company debt, corporate income taxes and other businesses that do not constitute an operating segment are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of September 30, 2017, Corporate/Other had $6.8 billion of stand-alone holding company long-term debt, of which $1.45 billion was subject to variable-interest rates, and $500 million was borrowed by FE under its revolving credit facility.

Segment Financial Information

For the Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other	Reconciling Adjustments	Consolidated
	(In millions)					
September 30, 2017						
External revenues	$2,610	$ 342	$ 796	$ —	$ (34)	$ 3,714
Internal revenues	—	—	93	—	(93)	—
Total revenues	2,610	342	889	—	(127)	3,714
Depreciation	183	59	30	17	—	289
Amortization of regulatory assets, net	85	6	—	—	—	91
Impairment of assets (Note 14)	—	13	18	—	—	31
Investment income	13	—	34	3	(13)	37
Interest expense	133	38	44	90	—	305
Income taxes (benefits)	183	49	40	(33)	—	239
Net income (loss)	314	84	66	(68)	—	396
Total assets	27,866	9,356	5,814	613	—	43,649
Total goodwill	5,004	614	—	—	—	5,618
Property additions	286	248	45	14	—	593
September 30, 2016						
External revenues	$2,691	$ 294	$ 998	$ —	$ (66)	$ 3,917
Internal revenues	—	—	117	—	(117)	—
Total revenues	2,691	294	1,115	—	(183)	3,917
Depreciation	169	47	79	16	—	311
Amortization of regulatory assets, net	98	—	—	—	—	98
Investment income	13	—	23	2	(10)	28
Interest expense	143	39	48	56	—	286
Income taxes (benefits)	162	50	49	(10)	—	251
Net income (loss)	276	85	86	(67)	—	380
Total assets	27,818	8,492	15,165	486	—	51,961
Total goodwill	5,004	614	—	—	—	5,618
Property additions	281	268	110	5	—	664
For the Nine Months Ended						
September 30, 2017						
External revenues	$7,362	$ 982	$ 2,388	$ —	$ (157)	$ 10,575
Internal revenues	—	—	296	—	(296)	—
Total revenues	7,362	982	2,684	—	(453)	10,575
Depreciation	540	164	87	54	—	845
Amortization of regulatory assets, net	204	11	—	—	—	215
Impairment of assets (Note 14)	—	13	149	—	—	162
Investment income	41	—	66	8	(37)	78
Interest expense	405	116	136	225	—	882
Income taxes (benefits)	442	154	(25)	(89)	—	482
Net income (loss)	756	264	(57)	(188)	—	775

Property additions	854	717	233	43	—	1,847
September 30, 2016						
External revenues	$7,390	$ 851	$ 3,158	$ —	$ (212)	$ 11,187
Internal revenues	—	—	377	—	(377)	—
Total revenues	7,390	851	3,535	—	(589)	11,187
Depreciation	504	138	284	48	—	974
Amortization of regulatory assets, net	218	4	—	—	—	222
Impairment of assets (Note 14)	—	—	1,447	—	—	1,447
Investment income	37	—	56	13	(31)	75
Interest expense	441	118	143	161	—	863
Income taxes (benefits)	336	143	(96)	(49)	—	334
Net income (loss)	573	244	(1,029)	(169)	—	(381)
Property additions	809	824	492	31	—	2,156

14. ASSET IMPAIRMENTS

Competitive Generation Asset Sale

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement (which was subsequently amended and restated as described below) to sell four of AE Supply's natural gas generating plants and approximately 59% of AGC's interest in the Bath County pumped hydro facility (1,572 MWs of combined capacity) to a subsidiary of LS Power for an all-cash purchase price of $925 million, subject to customary and other closing conditions, including receipt of regulatory approvals from FERC and the VSCC, as applicable, and various third-party consents. On February 17, 2017, AE Supply and AGC submitted a filing with FERC and on June 13, 2017, FERC issued an order authorizing such transaction as described in the January 2017 asset purchase agreement. On September 29, 2017, the parties filed a request with FERC for authorization to transfer the related hydroelectric license for Bath County under Part I of the FPA. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once all regulatory approvals are obtained. Additionally, the consent of VEPCO is needed for the sale of AGC's interest in the Bath County pumped hydro facility, as well as agreement among AGC, LS Power and VEPCO with respect to certain amendments to the Bath County project agreements.

On August 30, 2017, the parties, along with AE Supply's subsidiary BU Energy, executed an amended and restated asset purchase agreement to (1) reduce the purchase price to $825 million, subject to adjustments, (2) add BU Energy's 50% interest in a joint venture that owns the Buchanan Generating Facility (43 MWs) to the transaction and (3) provide that each component of the transaction (i.e., the AE Supply natural gas facilities, AGC's interest in the Bath County hydroelectric power station and BU Energy's interest in the Buchanan Generating Facility) may close independently. The sale of the AE Supply natural gas generating plants is expected to close in the fourth quarter of 2017 and the sale of approximately 59% of AGC's interests in the Bath County hydroelectric power station and BU Energy's 50% interest in the Buchanan Generating Facility are expected to close in the first quarter of 2018, subject in each case to various customary and other closing conditions including, without limitation, receipt of regulatory approvals and third-party consents, including the consent of VEPCO as discussed above. Under the amended and restated purchase agreement, AE Supply has agreed to satisfy and discharge all of its approximately $305 million of currently outstanding senior notes, which is expected to require the payment of a "make-whole" premium currently estimated to be approximately $100 million based on current interest rates, upon both (i) the consummation of the sale of the natural gas generating plants and (ii) either (a) the consummation of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station or (b) the consummation of the pending sale of the Pleasants Power Station by AE Supply to its affiliate, MP. As a further condition to closing, FE will provide the purchaser two limited three-year guarantees of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement. On September 29, 2017, the parties filed an application with FERC for authorization to complete the Buchanan Generating Facility sale. On October 20, 2017, the parties filed an application with the VSCC for approval of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station. There can be no assurance that all regulatory approvals will be obtained and/or all closing conditions will be satisfied or that any of the transactions will be consummated.

As a result of the amended asset purchase agreement, CES recorded non-cash pre-tax impairment charges of $158 million in the nine-month period ended September 30, 2017.

Assets held for sale as of September 30, 2017, include property, plant and equipment (net of accumulated provision for depreciation) of $765 million, investments of $20 million, materials and supplies inventory of $4 million, and AROs of approximately $1 million.

MAIT Transmission Formula Rate Settlement

As described in Note 10, “Regulatory Matters,” on October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC, which is subject to a final order. As a result of the settlement agreement, MAIT recorded a pre-tax impairment charge of $13 million in the third quarter of 2017.

Competitive Generation Deactivations and Other Exit Activities

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

Goodwill

As a result of low capacity prices associated with the 2019/2020 PJM Base Residual Auction in May 2016, as well as its annual update to its fundamental long-term capacity and energy price forecast, FirstEnergy determined that an interim impairment analysis of the CES reporting unit’s goodwill was necessary during the second quarter of 2016.

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

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

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

Termination of Customer Contract

During the third quarter of 2016, FES recorded a pre-tax charge of $32 million associated with the termination of a customer contract, which is included in Other operating expenses in the Consolidated Statement of Income (Loss).

ITEM 2. Management’s Discussion and Analysis of Registrant and Subsidiaries

FIRSTENERGY CORP.
MANAGEMENT’S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS
FIRSTENERGY’S BUSINESS

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

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, MAIT (effective January 31, 2017) and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP). The segment's revenues are primarily derived from forward-looking rates at ATSI and TrAIL, as well as stated transmission rates at certain of FirstEnergy’s utilities. As discussed in "Outlook - FERC Matters" below, MAIT and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. In March 2017, FERC approved JCP&L's and MAIT's forward-looking formula rate with effective dates of June 1, 2017, and July 1, 2017, respectively, both subject to refund pending the outcome of settlement and hearing proceedings and a final order by FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under forward-looking rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The CES segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. As of September 30, 2017, this business segment controlled 13,162 MWs of electric generating capacity, including, as further discussed below, 1,615 MWs of natural gas and hydroelectric generating capacity subject to an asset purchase agreement with a subsidiary of LS Power and the 1,300 MW Pleasants power station subject to an asset purchase agreement with MP resulting from MP's RFP process to address its generation shortfall. The CES segment’s operating results are primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs and capacity costs charged by PJM to deliver energy to the segment’s customers, as well as other operating and maintenance costs, including costs incurred by FENOC.

Corporate support not charged to FE's subsidiaries, interest expense on stand-alone holding company debt, corporate income taxes and other businesses that do not constitute an operating segment are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of September 30, 2017, Corporate/Other had $6.8 billion of stand-alone holding company long-term debt, of which $1.45 billion was subject to variable-interest rates, and $500 million was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

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

Over the past several years, CES has been impacted by a decrease in demand and excess generation supply in the PJM Region, which has resulted in low power and capacity prices, as well as significant environmental compliance costs. To address this, CES sold or deactivated more than 6,770 MWs of competitive generation from 2012 to 2015 and announced in 2016 plans to exit and/or deactivate an additional 856 MWs by 2020 related to the Bay Shore Unit 1 generating station and Units 1-4 of the W.H. Sammis generating station. Additionally, CES has continued to focus on cost reductions, including those identified as part of FirstEnergy’s previously disclosed cash flow improvement plan.

However, the energy and capacity markets remain weak with significantly low capacity clearing prices and current forward pricing as well as the long-term fundamental view on energy and capacity prices. In order to focus on stable and predictable cash flow from its regulated business units, in November of 2016, FirstEnergy announced a strategic review of its competitive operations with a target to implement its exit from competitive operations by mid-2018.

In connection with this strategic review, AE Supply and AGC entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating Facility and approximately 59% of AGC’s interest in Bath County (1,615 MWs of combined capacity) for an all-cash purchase price of $825 million, subject to adjustments. Closing of the transaction is subject to customary and other closing conditions including receipt of regulatory approvals from FERC and the VSCC, third party consents and the satisfaction and discharge of $305 million of AE Supply’s senior notes, which is expected to require the payment of a “make-whole” premium currently estimated to be approximately $100 million based on current interest rates, upon both (i) the consummation of the sale of the natural gas generating plants and (ii) either (a) the consummation of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station or (b) the consummation of the pending sale of the Pleasants Power Station by AE Supply to its affiliate, MP, as discussed below. As a further condition to closing, FE will provide the purchaser two limited three-year guarantees of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement. The sale of the natural gas generating plants is expected to close in the fourth quarter of 2017 and the sale of approximately 59% of AGC’s interests in the Bath County hydroelectric power station and BU Energy’s 50% interest in the Buchanan Generating Facility are expected to close in the first quarter of 2018. For additional information see "Outlook" below.

Additionally, AE Supply’s Pleasants power station (1,300 MWs) was selected in MP's RFP seeking additional generation capacity, and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire the Pleasants power station for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals as further discussed below.

The strategic options to exit the remaining portion of CES’ generation, which is primarily at FES, are still uncertain, but could include one or more of the following:

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

Furthermore, the implementation of various strategic options, and the timing thereof, could be impacted by various events, including, but not limited to the following:

- The outcome of efforts related to the NOPR released by the Secretary of Energy and action by FERC to address critical issues central to protecting the long-term reliability and resiliency of the electric grid provided by traditional baseload resources, such as coal and nuclear generation;
- The resolution of legislation before the Ohio General Assembly that would create a zero-emission nuclear (ZEN) program that would provide compensation to nuclear power plants for their fuel diversity, environmental and other benefits and the potential for similar legislative action in Pennsylvania; and/or
- The inability to finalize and consummate a settlement agreement with BNSF and NS regarding a previously disclosed long-term coal transportation contract dispute as discussed in "Outlook - Environmental Matters" below, whereby FG could be subject to materially higher damages.

Today, the competitive generation portfolio is comprised of more than 13,000 MWs of generation, primarily from coal, nuclear and natural gas and oil fuel sources. The assets can generate approximately 70-75 million MWHs annually, with up to an additional five million MWHs available from purchased power agreements for wind, solar, and CES' entitlement in OVEC, of which a portion is sold through various retail channels and the remainder targeting forward wholesale or spot sales. Subject to the completion of the AE Supply and AGC asset sale discussed above as well as the transfer of the Pleasants Power station to MP, the size and generation capacity of CES’ portfolio will be reduced to approximately 10,000 MWs, primarily at FES, with up to approximately 65 million MWHs produced annually.

The competitive business continues to be managed conservatively due to the stress of weak energy prices, insufficient results from recent capacity auctions and anemic demand forecasts. Furthermore, the credit quality of CES, specifically FES' unsecured debt rating of Caa1 at Moody’s, CCC- at S&P and C at Fitch and a negative outlook from Moody's and S&P, has challenged its ability to hedge generation with retail and forward wholesale sales due to significant collateral requirements. As a result, CES' contract sales are expected to decline from 53 million MWHs in 2016 to 40-45 million MWHs in 2017 and to 30-35 million MWHs in 2018. While the reduced contract sales will decrease potential collateral requirements, market price volatility may significantly impact CES' financial results due to the increased exposure to the wholesale spot market.

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of September 30, 2017, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. Furthermore, an inability to develop and execute upon viable alternative strategies for its competitive portfolio would continue to further stress the liquidity and financial condition of FES.

Cash flow from operations at FES is expected to be sufficient to fund capital expenditures, nuclear fuel purchases, and repay money pool borrowings through March 2018. However, as previously disclosed, FES has $515 million of maturing debt in 2018, beginning in the second quarter. Additionally, FES has $48 million of interest and lease payments in December 2017 and $38 million of interest payments in the first quarter of 2018. Based on FES' current senior unsecured debt rating, capital structure and the forecasted decline in wholesale forward market prices over the next few years, the debt maturities are likely to be difficult to refinance. Furthermore, lack of clarity regarding the timing and viability of alternative strategies, including additional asset sales or deactivations and/or converting generation from competitive operations to a regulated or regulated-like construct in a way that provides FES with the means to satisfy its obligations over the long-term, may also require FES to restructure debt and other financial obligations with its creditors and/or seek protection under U.S. bankruptcy laws. In the event FES seeks protection under U.S. bankruptcy laws, FENOC will likely seek such protection. Although management is exploring capital and other cost reductions, asset sales, and other options to improve cash flow as well as continuing with efforts to explore legislative or regulatory solutions, these obligations and their impact to liquidity raise substantial doubt about FES’ ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern.

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

Together, the Regulated Transmission and Distribution businesses are expected to provide stable, predictable earnings and cash flows to support FE’s dividend.

With more than 24,500 miles in operations, the transmission system is the centerpiece of FirstEnergy’s regulated investment strategy. Regulated Transmission's rate base compounded annual growth rate is expected to be 9% through 2021 as the company plans to invest $4.2 to $5.8 billion in capital from 2017 to 2021 as part of its Energizing the Future transmission plan, which began as a $4.2 billion investment plan from 2014 through 2017 to upgrade FirstEnergy's transmission system.

These investments continue to be focused in the stand-alone transmission companies with effective forward-looking formula rates including ATSI and TrAIL as well as forward-looking formula rates at MAIT and JCP&L, which FERC approved in March 2017 with effective dates of June 1, 2017 and July 1, 2017, respectively, both subject to refund pending further hearing and settlement proceedings and a final FERC order. FirstEnergy believes its existing transmission infrastructure creates incremental investment opportunities of approximately $20 billion beyond those identified through 2021 which will make the transmission system more reliable, robust, secure and resistant to extreme weather events, with improved operational flexibility. FirstEnergy plans to fund a portion of its long-term cash needs, including Regulated Transmission's capital program with at least $1.5 billion of equity through 2019, subject to market conditions and other factors, as discussed in "Capital Resources and Liquidity".

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

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

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Three Months Ended September 30				For the Nine Months Ended September 30			
	2017	2016	Change		2017	2016	Change	
REVENUES:	$3,714	$3,917	$(203)	(5)%	$10,575	$11,187	$(612)	(5)%
OPERATING EXPENSES:								
Fuel	363	450	(87)	(19)%	1,074	1,269	(195)	(15)%
Purchased power	861	979	(118)	(12)%	2,459	2,992	(533)	(18)%
Other operating expenses	942	953	(11)	(1)%	3,041	2,835	206	7 %
Provision for depreciation	289	311	(22)	(7)%	845	974	(129)	(13)%
Amortization of regulatory assets, net	91	98	(7)	(7)%	215	222	(7)	(3)%
General taxes	253	265	(12)	(5)%	777	786	(9)	(1)%
Impairment of assets	31	—	31	NM	162	1,447	(1,285)	(89)%
Total operating expenses	2,830	3,056	(226)	(7)%	8,573	10,525	(1,952)	(19)%
OPERATING INCOME	884	861	23	3 %	2,002	662	1,340	NM
OTHER INCOME (EXPENSE):								
Investment income	37	28	9	32 %	78	75	3	4 %
Interest expense	(305)	(286)	(19)	7 %	(882)	(863)	(19)	2 %
Capitalized financing costs	19	28	(9)	(32)%	59	79	(20)	(25)%
Total other expense	(249)	(230)	(19)	8 %	(745)	(709)	(36)	5 %
INCOME (LOSS) BEFORE INCOME TAXES	635	631	4	1 %	1,257	(47)	1,304	NM
INCOME TAXES	239	251	(12)	(5)%	482	334	148	44 %
NET INCOME (LOSS)	$396	$380	$16	4 %	$775	$(381)	$1,156	NM
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:								
Basic	$0.89	$0.89	$—	— %	$1.75	$(0.90)	$2.65	NM
Diluted	$0.89	$0.89	$—	— %	$1.74	$(0.90)	$2.64	NM

* NM = not meaningful

For the Three Months Ended September 30, 2017

FirstEnergy’s net income in the third quarter of 2017 was $396 million, or basic and diluted earnings of $0.89 per share of common stock, compared to net income of $380 million, or basic and diluted earnings of $0.89 per share of common stock in the third quarter of 2016.

During the third quarter of 2017, FirstEnergy's revenues decreased $203 million, as compared to the same period in 2016, resulting from a $226 million decrease at CES and a $81 million decrease at Regulated Distribution, partially offset by a $48 million increase at Regulated Transmission.

- The decrease in revenue at CES was primarily due to lower contract sales volumes and lower retail prices partially offset by higher wholesale sales.

- The decrease in revenue at Regulated Distribution was primarily due to the impact of lower weather-related usage and higher customer shopping partially offset by higher distribution revenues reflecting the implementation of new rates in January 2017.
- The increase in revenue at Regulated Transmission resulted from a higher rate base at ATSI, JCP&L and TrAIL as well as recovery of incremental operating expenses.

Operating expenses decreased $226 million in the third quarter of 2017, as compared to the third quarter of 2016, primarily reflecting a decrease of $184 million at CES and $131 million at Regulated Distribution. Changes in certain operating expenses include the following:

- Purchased power decreased $118 million, primarily at Regulated Distribution as a result of lower volumes from increased customer shopping and lower weather-related usage as well as lower default service auction prices. The decline in purchased power at CES was due to lower capacity expenses and market prices.
- Fuel expense decreased $87 million, primarily at CES due to lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices. The decline in fuel expense at Regulated Distribution resulted from lower unit costs.
- Depreciation expense decreased $22 million, primarily due to a lower asset base at CES resulting from asset impairments recognized in 2016.
- Other operating expenses decreased $11 million, primarily due to the absence of a termination charge associated with an FES Governmental Aggregation customer contract.

- Impairment of assets increased $31 million, resulting primarily from purchase price adjustments pursuant to the terms of the amended and restated asset purchase agreement between AE Supply, AGC, BU Energy and a subsidiary of LS Power.

Other expense increased $19 million primarily from higher interest expense.

FirstEnergy’s effective tax rate was 37.6% and 39.8% for the three months ended September 30, 2017 and 2016, respectively.

For the Nine Months Ended September 30, 2017

For the nine months ended September 30, 2017, FirstEnergy’s net income was $775 million, or basic earnings of $1.75 per share of common stock ($1.74 diluted), compared with a net loss of $(381) million, or a basic and diluted loss of $(0.90) per share of common stock, for the nine months ended September 30, 2016.

FirstEnergy's earnings for the nine months ended September 30, 2017, increased $1,156 million, as compared to the same period of 2016, primarily due to lower asset impairment and plant exit costs. In the second quarter of 2016, CES recognized pre-tax asset impairment and plant exit costs as follows:

- Non-cash pre-tax impairment charges of $800 million associated with goodwill at CES;
- Non-cash pre-tax impairment charges of $647 million associated with the announced plan to exit operations by 2020 of Units 1-4 of the W.H. Sammis generating station and the Bay Shore Unit 1 generating station;
- Coal contract settlement and termination pre-tax costs of $58 million, and
- Valuation allowances against state and local NOL carryforwards of $159 million.

During the first nine months of 2017, FirstEnergy’s revenues decreased $612 million, as compared to the same period in 2016, resulting from a $851 million decrease at CES and a $28 million decrease at Regulated Distribution, partially offset by a $131 million increase at Regulated Transmission.

- The decrease in revenue at CES was primarily due to lower contract sales volumes at lower prices and lower capacity revenues, partially offset by an increase in wholesale sales.
- The decrease in revenue at Regulated Distribution primarily resulted from lower weather-related usage and higher customer shopping partially offset by new rates implemented in January 2017.
- The increase in revenue at Regulated Transmission resulted from a higher rate base at ATSI, JCP&L and TrAIL as well as recovery of incremental operating expenses.

Operating expenses decreased $1,952 million in the first nine months of 2017, as compared to the same period of 2016, primarily reflecting a decrease at CES of $1,884 million principally due to the asset impairment and plant exit costs discussed above. Changes in certain operating expenses include the following:

- Fuel expense decreased $195 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts in 2016 and lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices.
- Purchased power decreased $533 million, primarily at CES, due to lower capacity expense as a result of lower contract sales and lower unit costs. At Regulated Distribution, the decline in purchased power was the result of lower volumes from increased customer shopping and lower weather-related usage as well as lower default service auction prices.
- Other operating expenses increased $206 million, reflecting an increase of $117 million at CES, primarily associated with estimated losses on long-term coal transportation contract disputes recognized in the first quarter of 2017 and higher non-cash mark-to-market losses on commodity contract positions. Operating expenses increased $31 million at Regulated Distribution resulting primarily from higher operating and maintenance expenses, including increased storm restoration costs.

- Depreciation expense decreased $129 million, primarily due to a lower asset base at CES resulting from asset impairments recognized in 2016.

Other expense increased $36 million, primarily from higher interest expense and lower capitalized financing costs.

FirstEnergy's effective tax rate for the nine months ended September 30, 2017 was 38.3%. For the nine months ended September 30, 2017, the change in the effective tax rate, as compared to the same period for 2016, is primarily due to the impairment of $800 million of goodwill recognized in 2016, of which $433 million was non-deductible for tax purposes. Additionally, $159 million of valuation allowances were recorded in 2016 against state and municipal NOL carryforwards that also impacted the 2016 effective tax rate.

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

Summary of Results of Operations — Third Quarter 2017 Compared with Third Quarter 2016

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

Third Quarter 2017 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,563	$ 342	$ 790	$ (44)	$ 3,651
Other	47	—	6	10	63
Internal	—	—	93	(93)	—
Total Revenues	2,610	342	889	(127)	3,714
Operating Expenses:					
Fuel	126	—	237	—	363
Purchased power	797	—	157	(93)	861
Other operating expenses	620	55	324	(57)	942
Provision for depreciation	183	59	30	17	289
Amortization of regulatory assets, net	85	6	—	—	91
General taxes	187	45	14	7	253
Impairment of assets	—	13	18	—	31
Total Operating Expenses	1,998	178	780	(126)	2,830
Operating Income (Loss)	612	164	109	(1)	884
Other Income (Expense):					
Investment income (loss)	13	—	34	(10)	37
Interest expense	(133)	(38)	(44)	(90)	(305)
Capitalized financing costs	5	7	7	—	19
Total Other Expense	(115)	(31)	(3)	(100)	(249)
Income (Loss) Before Income Taxes (Benefits)	497	133	106	(101)	635
Income taxes (benefits)	183	49	40	(33)	239
Net Income (Loss)	$314	$ 84	$ 66	$ (68)	$ 396

Third Quarter 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,638	$ 294	$ 959	$ (44)	$ 3,847
Other	53	—	39	(22)	70
Internal	—	—	117	(117)	—
Total Revenues	2,691	294	1,115	(183)	3,917
Operating Expenses:					
Fuel	156	—	294	—	450
Purchased power	902	—	194	(117)	979
Other operating expenses	614	45	367	(73)	953
Provision for depreciation	169	47	79	16	311
Amortization of regulatory assets, net	98	—	—	—	98
General taxes	190	37	30	8	265
Impairment of assets	—	—	—	—	—
Total Operating Expenses	2,129	129	964	(166)	3,056
Operating Income (Loss)	562	165	151	(17)	861
Other Income (Expense):					
Investment income (loss)	13	—	23	(8)	28
Interest expense	(143)	(39)	(48)	(56)	(286)
Capitalized financing costs	6	9	9	4	28
Total Other Expense	(124)	(30)	(16)	(60)	(230)
Income (Loss) Before Income Taxes (Benefits)	438	135	135	(77)	631
Income taxes (benefits)	162	50	49	(10)	251
Net Income (Loss)	$276	$ 85	$ 86	$ (67)	$ 380

Changes Between Third Quarter 2017 and Third Quarter 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(75)	$ 48	$ (169)	$ —	$ (196)
Other	(6)	—	(33)	32	(7)
Internal	—	—	(24)	24	—
Total Revenues	(81)	48	(226)	56	(203)
Operating Expenses:					
Fuel	(30)	—	(57)	—	(87)
Purchased power	(105)	—	(37)	24	(118)
Other operating expenses	6	10	(43)	16	(11)
Provision for depreciation	14	12	(49)	1	(22)
Amortization of regulatory assets, net	(13)	6	—	—	(7)
General taxes	(3)	8	(16)	(1)	(12)
Impairment of assets	—	13	18	—	31
Total Operating Expenses	(131)	49	(184)	40	(226)
Operating Income (Loss)	50	(1)	(42)	16	23
Other Income (Expense):					
Investment income (loss)	—	—	11	(2)	9
Interest expense	10	1	4	(34)	(19)
Capitalized financing costs	(1)	(2)	(2)	(4)	(9)
Total Other Expense	9	(1)	13	(40)	(19)
Income (Loss) Before Income Taxes (Benefits)	59	(2)	(29)	(24)	4
Income taxes (benefits)	21	(1)	(9)	(23)	(12)
Net Income (Loss)	$38	$ (1)	$ (20)	$ (1)	$ 16

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Regulated Distribution — Third Quarter 2017 Compared with Third Quarter 2016

Regulated Distribution's operating results increased $38 million in the third quarter of 2017, as compared to the same period of 2016, reflecting implementation of approved rates in Ohio, Pennsylvania, and New Jersey, as further described below, partially offset by lower weather-related customer usage.

Revenues —

The $81 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended September 30 2017	2016	Increase (Decrease)
	(In millions)		
Distribution services	$1,441	$1,363	$ 78
Generation sales:			
Retail	990	1,133	(143)
Wholesale	132	142	(10)
Total generation sales	1,122	1,275	(153)
Other	47	53	(6)
Total Revenues	$2,610	$2,691	$ (81)

Distribution services revenues increased $78 million primarily resulting from the implementation of the DMR in Ohio, effective January 1, 2017, approved base distribution rate increases in Pennsylvania and New Jersey, effective January 27, 2017, and January 1, 2017, respectively, and higher revenue from the DCR in Ohio. Partially offsetting these rate increases was a decline in MWH deliveries, primarily resulting from lower weather-related usage, as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Three Months Ended September 30 2017	2016	Increase (Decrease)
	(In thousands)		
Residential	13,863	16,138	(14.1)%
Commercial	11,228	12,005	(6.5)%
Industrial	13,173	13,023	1.2%
Other	147	144	2.1%
Total Electric Distribution MWH Deliveries	38,411	41,310	(7.0)%

Lower distribution deliveries to residential and commercial customers primarily reflect lower weather-related usage resulting from cooling degree days that were 27% below 2016, and 3% above normal. Deliveries to industrial customers increased reflecting higher shale and steel customer usage.

The following table summarizes the price and volume factors contributing to the $153 million decrease in generation revenues for the third quarter of 2017 compared to the same period of 2016:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$ (121)
Change in prices	(22)
	(143)
Wholesale:	
Effect of decrease in sales volumes	(4)
Change in prices	(8)
Capacity Revenue	2
	(10)
Decrease in Generation Revenues	$ (153)

The decrease in retail generation sales volumes was primarily due to decreased weather-related usage, as described above, as well as increased customer shopping in Ohio, Pennsylvania, and New Jersey. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 86% from 85% for the Ohio Companies, to 68% from 66% for the Pennsylvania Companies, and to 50% from 48% for JCP&L. The decrease in retail generation prices primarily resulted from lower default service auction prices in Pennsylvania and New Jersey.

Wholesale generation revenues decreased $10 million in the third quarter of 2017, as compared to the same period in 2016, primarily due to lower spot market energy prices. 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 $131 million primarily due to the following:

- Fuel expense decreased $30 million in the third quarter of 2017, as compared to the same period in 2016, primarily related to lower unit costs.

- Purchased power costs were $105 million lower in the third quarter of 2017, as compared to the same period in 2016, primarily due to lower default service auction prices as well as decreased volumes resulting from increased customer shopping and lower weather-related usage, as described above.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (30)
Change due to decreased volumes	(85)
	(115)
Purchases from affiliates:	
Change due to decreased unit costs	(4)

Change due to decreased volumes	(20)
	(24)
Capacity Expense	12
Amortization of deferred costs	22
Decrease in Purchased Power Costs	$ (105)

- Depreciation expense increased $14 million primarily due to a higher asset base as well as increased rates in Pennsylvania.

- Amortization expense decreased $13 million primarily due to lower amortization of transition costs and non-utility generation costs, partially offset by lower deferral of storm costs.

Other Expense —

Total other expense decreased $9 million primarily due to lower interest expense resulting from various debt maturities at JCP&L and CEI.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.8% and 37.0% for the quarter ended September 30, 2017 and 2016, respectively.

Regulated Transmission — Third Quarter 2017 Compared with Third Quarter 2016

Regulated Transmission's operating results decreased $1 million in the third quarter of 2017, as compared to the same period of 2016, primarily resulting from a pre-tax impairment charge of $13 million, as discussed below, partially offset by the impact of a higher rate base at ATSI and TrAIL. Additionally, JCP&L's and MAIT's forward-looking formula rates for their transmission assets were implemented on June 1, 2017, and July 1, 2017, respectively, subject to refund pending the outcome of settlement and hearing proceedings and a final FERC order.

Revenues —

Total revenues increased $48 million principally due to the recovery of incremental operating expenses and a higher rate base at ATSI, JCP&L, and TrAIL.

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

Revenues by Transmission Asset Owner	For the Three Months Ended September 30 2017	2016	Increase (Decrease)
	(In millions)		
ATSI	$167	$139	$ 28
TrAIL	72	67	5
MAIT [1]	29	25	4
JCP&L	35	23	12
Other	39	40	(1)
Total Revenues	$342	$294	$ 48

(1) Revenues in 2016 represent transmission revenues under stated rates at ME and PN.

Operating Expenses —

Total operating expenses increased $49 million, principally due to higher operating and maintenance expenses as well as higher property taxes and depreciation due to higher asset base. Additionally, as a result of the settlement agreement between MAIT and certain parties, MAIT recorded a pre-tax impairment charge of $13 million in the third quarter of 2017. The settlement agreement is currently pending at FERC.

Income Taxes —

Regulated Transmission's effective tax rate was 36.8% and 37.0% for the quarter ended September 30, 2017 and 2016, respectively.

CES — Third Quarter 2017 Compared with Third Quarter 2016

CES' operating results decreased $20 million in the third quarter of 2017, as compared to the same period of 2016, primarily due to an asset impairment charge of $18 million, as discussed below, and higher non-cash mark-to-market losses on commodity contract positions, partially offset by an increase in short-term (net-hourly position) transactions, the absence of a termination charge associated with an FES Governmental Aggregation customer contract, and lower depreciation expense.

Revenues —

Total revenues decreased $226 million in the third quarter of 2017, as compared to the same period of 2016, primarily due to lower contract sales volumes and lower retail prices, partially offset by an increase in short-term (net hourly position) transactions, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended September 30 2017	2016	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$173	$207	$ (34)
Governmental Aggregation	109	235	(126)
Mass Market	32	47	(15)
POLR	120	165	(45)
Structured	97	94	3
Total Contract Sales	531	748	(217)
Wholesale	342	311	31
Transmission	10	17	(7)
Other	6	39	(33)
Total Revenues	$889	$1,115	$ (226)

MWH Sales by Channel	For the Three Months Ended September 30 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	3,646	3,913	(6.8)%
Governmental Aggregation	1,932	4,238	(54.4)%
Mass Market	478	673	(29.0)%
POLR	2,170	2,893	(25.0)%
Structured	2,657	2,437	9.0 %
Total Contract Sales	10,883	14,154	(23.1)%
Wholesale	6,363	4,447	43.1 %
Total MWH Sales	17,246	18,601	(7.3)%

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

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease)				
	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(14)	$(20)	$ —	$ —	$(34)
Governmental Aggregation	(128)	2	—	—	(126)
Mass Market	(14)	(1)	—	—	(15)
POLR	(41)	(4)	—	—	(45)
Structured	9	(6)	—	—	3
Wholesale	56	(10)	(24)	9	31

The decrease in Direct, Governmental Aggregation and Mass Market revenues were primarily due to lower volumes. Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract in 2016. The Direct, Governmental Aggregation and Mass Market customer base was approximately 842,000 as of September 30, 2017, compared to 1.4 million as of September 30, 2016.

The decrease in POLR revenue of $45 million was primarily due to lower volumes.

Wholesale revenues increased $31 million, primarily due to an increase in short-term (net hourly position) transactions at lower market prices and higher capacity revenue, partially offset by lower net gains on financially settled contracts.

Other revenue decreased $33 million, primarily due to lower lease revenues from the expiration of a nuclear sale-leaseback agreement. CES earned lease revenue associated with the lessor equity interests it had purchased in sale-leaseback transactions, which expired in June 2017.

Operating Expenses —

Total operating expenses decreased $184 million in the third quarter of 2017 due to the following:

- Fuel costs decreased $57 million, primarily due to lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as described above.
- Purchased power costs decreased $37 million due to lower capacity expense ($20 million) and lower unit costs ($25 million), partially offset by higher volumes ($8 million). The decrease in capacity expense, which is a component of CES' retail price, was primarily the result of lower contract sales.

- Transmission expenses decreased $25 million, primarily due to lower contract sales volumes.

- Other operating expenses decreased $18 million, primarily due to the absence of a termination charge associated with an FES Governmental Aggregation customer contract, partially offset by higher non-cash mark-to-market losses on commodity contract positions.

- Depreciation expense decreased $49 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016, partially offset by the absence of an out-of-period adjustment to reduce the depreciation of a hydroelectric generating station in the third quarter of 2016.

- General taxes decreased $16 million, primarily due to lower property taxes and reduced gross receipts taxes associated with lower retail sales volumes.
- Impairment of assets were $18 million in the third quarter of 2017, primarily resulting from adjustments pursuant to the terms of the amended and restated asset purchase agreement between AE Supply, AGC, BU Energy and a subsidiary of LS Power as further discussed under "Outlook - Asset Impairment - Competitive Generation Asset Sale" below.

Other Expense —

Total other expense decreased $13 million in the third quarter of 2017, as compared to the same period of 2016, primarily due to higher investment income on NDT investments.

Income Taxes —

CES' effective tax rate was 37.7% and 36.3% for the quarter ended September 30, 2017 and 2016, respectively.

Corporate / Other — Third Quarter 2017 Compared with Third Quarter 2016

Financial results from the Corporate/Other operating segment and reconciling adjustments, including interest expense on holding company debt, corporate support services revenues and expenses and income taxes, resulted in a $1 million decrease in consolidated earnings in the third quarter of 2017, compared to the same period of 2016, primarily associated with higher interest expense, partially offset by a lower consolidated effective tax rate. Higher interest expense resulted from the issuance of $3 billion of senior notes in June of 2017, proceeds of which were used to repay short-term borrowings and redeem $650 million of notes due in 2018.

Summary of Results of Operations — First Nine Months of 2017 Compared with First Nine Months of 2016

Financial results for FirstEnergy's business segments in the first nine months of 2017 and 2016 were as follows:

First Nine Months 2017 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$7,222	$ 982	$ 2,313	$ (128)	$ 10,389
Other	140	—	75	(29)	186
Internal	—	—	296	(296)	—
Total Revenues	7,362	982	2,684	(453)	10,575
Operating Expenses:					
Fuel	388	—	686	—	1,074
Purchased power	2,267	—	488	(296)	2,459
Other operating expenses	1,871	150	1,237	(217)	3,041
Provision for depreciation	540	164	87	54	845
Amortization of regulatory assets, net	204	11	—	—	215
General taxes	546	130	71	30	777
Impairment of assets	—	13	149	—	162
Total Operating Expenses	5,816	468	2,718	(429)	8,573
Operating Income (Loss)	1,546	514	(34)	(24)	2,002
Other Income (Expense):					
Investment income (loss)	41	—	66	(29)	78
Interest expense	(405)	(116)	(136)	(225)	(882)
Capitalized financing costs	16	20	22	1	59
Total Other Expense	(348)	(96)	(48)	(253)	(745)
Income (Loss) Before Income Taxes (Benefits)	1,198	418	(82)	(277)	1,257
Income taxes (benefits)	442	154	(25)	(89)	482
Net Income (Loss)	$756	$ 264	$ (57)	$ (188)	$ 775

First Nine Months 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$7,205	$ 851	$ 3,023	$ (129)	$ 10,950
Other	185	—	135	(83)	237
Internal	—	—	377	(377)	—
Total Revenues	7,390	851	3,535	(589)	11,187
Operating Expenses:					
Fuel	436	—	833	—	1,269
Purchased power	2,549	—	820	(377)	2,992
Other operating expenses	1,840	115	1,120	(240)	2,835
Provision for depreciation	504	138	284	48	974
Amortization of regulatory assets, net	218	4	—	—	222
General taxes	545	114	98	29	786
Impairment of assets	—	—	1,447	—	1,447
Total Operating Expenses	6,092	371	4,602	(540)	10,525
Operating Income (Loss)	1,298	480	(1,067)	(49)	662
Other Income (Expense):					
Investment income (loss)	37	—	56	(18)	75
Interest expense	(441)	(118)	(143)	(161)	(863)
Capitalized financing costs	15	25	29	10	79
Total Other Expense	(389)	(93)	(58)	(169)	(709)
Income (Loss) Before Income Taxes (Benefits)	909	387	(1,125)	(218)	(47)
Income taxes (benefits)	336	143	(96)	(49)	334
Net Income (Loss)	$573	$ 244	$ (1,029)	$ (169)	$ (381)

Changes Between First Nine Months 2017 and First Nine Months 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$17	$ 131	$ (710)	$ 1	$ (561)
Other	(45)	—	(60)	54	(51)
Internal	—	—	(81)	81	—
Total Revenues	(28)	131	(851)	136	(612)
Operating Expenses:					
Fuel	(48)	—	(147)	—	(195)
Purchased power	(282)	—	(332)	81	(533)
Other operating expenses	31	35	117	23	206
Provision for depreciation	36	26	(197)	6	(129)
Amortization of regulatory assets, net	(14)	7	—	—	(7)
General taxes	1	16	(27)	1	(9)
Impairment of assets	—	13	(1,298)	—	(1,285)
Total Operating Expenses	(276)	97	(1,884)	111	(1,952)
Operating Income (Loss)	248	34	1,033	25	1,340
Other Income (Expense):					
Investment income (loss)	4	—	10	(11)	3
Interest expense	36	2	7	(64)	(19)
Capitalized financing costs	1	(5)	(7)	(9)	(20)
Total Other Expense	41	(3)	10	(84)	(36)
Income (Loss) Before Income Taxes (Benefits)	289	31	1,043	(59)	1,304
Income taxes (benefits)	106	11	71	(40)	148
Net Income (Loss)	$183	$ 20	$ 972	$ (19)	$ 1,156

Regulated Distribution — First Nine Months of 2017 Compared with First Nine Months of 2016

Regulated Distribution's operating results increased $183 million in the first nine months of 2017, as compared to the same period of 2016, reflecting implementation of approved rates in Ohio, Pennsylvania, and New Jersey, partially offset by lower weather-related customer usage, as further described below. Additionally, in the first quarter of 2016, the Ohio Companies recognized $51 million in regulatory charges resulting from the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.

Revenues —

The $28 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Nine Months Ended September 30 2017	2016	Increase (Decrease)
	(In millions)		
Distribution services	$4,003	$3,599	$ 404
Generation sales:			
Retail	2,851	3,222	(371)
Wholesale	368	384	(16)
Total generation sales	3,219	3,606	(387)
Other	140	185	(45)
Total Revenues	$7,362	$7,390	$ (28)

Distribution services revenues increased $404 million primarily resulting from the implementation of the DMR in Ohio, effective January 1, 2017, approved base distribution rate increases in Pennsylvania and New Jersey, effective January 27, 2017, and January 1, 2017, respectively, and higher revenue from the DCR in Ohio. Partially offsetting these rate increases was a decline in MWH deliveries, primarily resulting from lower weather-related usage, as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Nine Months Ended September 30 2017	2016	Increase (Decrease)
	(In thousands)		
Residential	38,846	42,130	(7.8)%
Commercial	31,693	32,913	(3.7)%
Industrial	38,571	37,746	2.2 %
Other	428	437	(2.1)%
Total Electric Distribution MWH Deliveries	109,538	113,226	(3.3)%

Lower distribution deliveries to residential and commercial customers primarily reflect lower weather-related usage resulting from heating degree days that were 11% below 2016, and 17% below normal as well as cooling degree days that were 21% below 2016, and 5% above normal. Deliveries to industrial customers increased reflecting higher shale and steel customer usage.

The following table summarizes the price and volume factors contributing to the $387 million decrease in generation revenues for the first nine months of 2017 compared to the same period of 2016:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$ (256)
Change in prices	(115)
	(371)
Wholesale:	
Effect of increase in sales volumes	12
Change in prices	(10)
Capacity Revenue	(18)
	(16)
Decrease in Generation Revenues	$ (387)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio and Pennsylvania as well as lower weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 85% from 82% for the Ohio Companies, to 68% from 67% for the Pennsylvania Companies, and to 52% from 51% for JCP&L. The decrease in retail generation prices primarily resulted from lower default service auction prices in Ohio, Pennsylvania, and New Jersey.

Wholesale generation revenues decreased $16 million in the first nine months of 2017, as compared to the same period in 2016, primarily due to lower spot market energy prices and capacity revenue, partially offset by higher wholesale sales. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery or refund, with no material impact to earnings.

Other revenues decreased $45 million primarily related to a $26 million gain on the sale of oil and gas rights at WP recognized in 2016 as well as $14 million in lower transition cost recovery revenues in New Jersey.

Operating Expenses —

Total operating expenses decreased $276 million primarily due to the following:

- Fuel expense decreased $48 million in the first nine months of 2017, as compared to the same period in 2016, primarily related to lower unit costs.

- Purchased power costs decreased $282 million during the first nine months of 2017, as compared to the same period of 2016, primarily due to decreased volumes resulting from increased customer shopping and lower weather-related usage, as described above, as well as lower default service auction prices. These lower costs were partially offset by recovery of previously deferred energy and fuel costs.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (125)
Change due to volumes	(164)

	(289)
Purchases from affiliates:	
Change due to decreased unit costs	(21)
Change due to volumes	(60)
	(81)
Capacity Expense	(1)
Amortization of deferred costs	89
Decrease in Purchased Power Costs	$ (282)

- Other operating expenses increased $31 million primarily due to:
  - Higher network transmission expenses of $14 million. The difference between current revenues and transmission costs incurred are deferred for future recovery or refund, resulting in no material impact on current period earnings.
  - Higher operating and maintenance expenses of $68 million, including increased expenses in Pennsylvania recovered through the new base distribution rates, effective January 27, 2017, and increased storm restoration costs, which were deferred for future recovery, resulting in no material impact on current period earnings.
  - Lower regulatory costs of $51 million resulting from the recognition in 2016 of economic development and energy efficiency obligations in accordance with the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.

- Depreciation expense increased $36 million primarily due to a higher rate base as well as increased rates in Pennsylvania.

- Amortization expense decreased $14 million primarily due to lower amortization of transition costs and non-utility generation costs, as well as higher deferral of storm restoration costs, partially offset by a lower deferral of transmission costs in Ohio.

Other Expense —

Total other expense decreased $41 million primarily due to lower interest expense resulting from various debt maturities at JCP&L, CEI, and OE.

Income Taxes —

Regulated Distribution's effective tax rate was 36.9% and 37.0% for the first nine months of 2017 and 2016, respectively.

Regulated Transmission — First Nine Months of 2017 Compared with First Nine Months of 2016

Regulated Transmission's operating results increased $20 million in the first nine months of 2017, as compared to the same period of 2016, primarily resulting from the impact of a higher rate base at ATSI and TrAIL partially offset by a pre-tax impairment charge of $13 million, as discussed below. Additionally, JCP&L's and MAIT's forward-looking formula rates for their transmission assets were implemented on June 1, 2017, and July 1, 2017, respectively, subject to refund pending the outcome of settlement and hearing proceedings and a final FERC order.

Revenues —

Total revenues increased $131 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI, JCP&L, and TrAIL.

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

	For the Nine Months Ended September 30		Increase
Revenues by Transmission Asset Owner	2017	2016	(Decrease)

	(In millions)		
ATSI	$485	$401	$ 84
TrAIL	215	187	28
MAIT [1]	79	75	4
JCP&L	86	69	17
Other	117	119	(2)
Total Revenues	$982	$851	$ 131

[1] Revenues in 2016 represent transmission revenues under stated rates at ME and PN.

Operating Expenses —

Total operating expenses increased $97 million principally due to higher operating and maintenance expenses, as well as higher property taxes and depreciation due to higher asset base. Additionally, as a result of the settlement agreement between MAIT and certain parties, MAIT recorded a pre-tax impairment charge of $13 million in the third quarter of 2017. The settlement agreement is currently pending at FERC.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.8% and 37.0% for the first nine months of 2017 and 2016, respectively.

CES — First Nine Months of 2017 Compared with First Nine Months of 2016

CES' operating results increased $972 million in the first nine months of 2017, as compared to the same period of 2016, primarily due to lower asset impairment and plant exit costs, as discussed above, and lower depreciation expense, partially offset by a pre-tax charge of $164 million associated with estimated losses on long-term coal transportation contract disputes, as discussed in "Outlook - Environmental Matters" below, higher non-cash mark-to-market losses on commodity contract positions, and lower capacity revenue.

Revenues —

Total revenues decreased $851 million in the first nine months of 2017, as compared to the same period of 2016, primarily due to lower capacity auction prices, lower contract sales volumes at lower prices, and lower net gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Nine Months Ended September 30 2017	2016	Decrease
	(In millions)		
Contract Sales:			
Direct	$560	$610	$ (50)
Governmental Aggregation	302	666	(364)
Mass Market	97	133	(36)
POLR	389	447	(58)
Structured	255	371	(116)
Total Contract Sales	1,603	2,227	(624)
Wholesale	971	1,117	(146)
Transmission	35	56	(21)
Other	75	135	(60)
Total Revenues	$2,684	$3,535	$ (851)

MWH Sales by Channel	For the Nine Months Ended September 30 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	11,504	11,391	1.0 %
Governmental Aggregation	5,686	10,798	(47.3)%
Mass Market	1,425	1,912	(25.5)%
POLR	6,983	7,526	(7.2)%

Structured	6,564	9,175	(28.5)%
Total Contract Sales	32,162	40,802	(21.2)%
Wholesale	16,753	9,938	68.6 %
Total MWH Sales	48,915	50,740	(3.6)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$6	$(56)	$ —	$ —	$(50)
Governmental Aggregation	(316)	(48)	—	—	(364)
Mass Market	(34)	(2)	—	—	(36)
POLR	(32)	(26)	—	—	(58)
Structured	(108)	(8)	—	—	(116)
Wholesale	190	11	(113)	(234)	(146)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract in 2016. Although unit pricing in Direct, Governmental Aggregation and Mass Market was lower year-over-year, the decrease was primarily attributable to lower capacity expense as discussed below, which is a component of the retail price.

The decrease in POLR revenue of $58 million was primarily due to lower volumes and lower unit prices. Structured revenue decreased $116 million, primarily due to the impact of lower transaction volumes.

Wholesale revenues decreased $146 million, primarily due to a decrease in capacity revenue from lower capacity auction prices and lower net gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions at higher market prices.

Transmission revenue decreased $21 million, primarily due to lower congestion revenue.

Other revenue decreased $60 million, primarily due to lower lease revenues from the expiration of a nuclear sale-leaseback agreement. CES earned lease revenue associated with the lessor equity interests it has purchased in sale-leaseback transactions, one of which expired in June 2017 and another in May 2016.

Operating Expenses —

Total operating expenses decreased $1,884 million in the first nine months of 2017, compared to the same period of 2016, due to the following:

- Fuel costs decreased $147 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts recognized in 2016, as well as lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as described above, partially offset by higher unit costs.
- Purchased power costs decreased $332 million, primarily due to lower capacity expenses ($254 million) and lower unit costs ($91 million), partially offset by higher volumes ($13 million). The decrease in capacity expense, which is a component of CES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with CES' retail sales obligations. Lower unit costs primarily resulted from lower wholesale spot market prices, as discussed above.
- A $164 million charge associated with estimated losses on long-term coal transportation contract disputes was recognized in the first quarter of 2017, as discussed in "Outlook - Environmental Matters" below.

- Fossil operating and maintenance expenses decreased $42 million, primarily due to lower outage costs and the absence of plant demolition costs recognized in 2016.

- Nuclear operating and maintenance expenses increased $18 million, primarily as a result of higher refueling outage costs, partially offset by lower non-outage maintenance costs. There were two refueling outages during the first nine months of 2017, as compared to one refueling outage during the same period of 2016.

- Transmission expenses decreased $51 million, primarily due to lower contract sales volumes.

- Other operating expenses increased $28 million, primarily due to higher non-cash mark-to-market losses on commodity contract positions, partially offset by the absence of a termination charge associated with an FES Governmental Aggregation customer contract.

- Depreciation expense decreased $197 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016, partially offset by the absence of an out-of-period adjustment to reduce the depreciation of a hydroelectric generating station in the third quarter of 2016.
- General taxes decreased $27 million, primarily due to lower property taxes and reduced gross receipts taxes associated with lower retail sales volumes.
- Impairment of assets decreased $1,298 million primarily due to the absence of an $800 million impairment of goodwill and a $647 million impairment of Units 1-4 of the W.H. Sammis generating station and the Bay Shore Unit 1 generating station in 2016, partially offset by impairment charges recognized in 2017 resulting from the amended and restated asset purchase agreement between AE Supply, AGC, BU Energy and a subsidiary of LS Power as further discussed under "Outlook - Asset Impairment - Competitive Generation Asset Sale" below.

Other Expense —

Total other expense decreased $10 million in the first nine months of 2017, as compared to the same period of 2016, primarily due to higher investment income on NDT investments.

Income Taxes (Benefits) —

CES' effective tax rate was 30.5% and 8.5% on pre-tax losses for the first nine months of 2017 and 2016, respectively. The change in the effective tax rate is primarily due to the impairment of $800 million of goodwill recognized in 2016, of which $433 million was non-deductible for tax purposes. Additionally, $159 million of valuation allowances were recognized in 2016 against state and municipal NOL carryforwards.

Corporate / Other — First Nine Months of 2017 Compared with First Nine Months of 2016

Financial results from the Corporate/Other operating segment and reconciling adjustments resulted in a $19 million decrease in consolidated earnings in the first nine months of 2017 compared to the same period of 2016 primarily associated with higher interest expense, partially offset by a change in consolidated effective tax rate. Higher interest expense resulted from higher average borrowings on the FE revolving credit facility and the issuance of $3 billion of senior notes in June of 2017.

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of September 30, 2017 and December 31, 2016, and the changes during the nine months ended September 30, 2017:

Net Regulatory Assets by Source	September 30, 2017	December 31, 2016	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$51	$ 90	$ (39)
Customer receivables for future income taxes	375	444	(69)
Nuclear decommissioning and spent fuel disposal costs	(174)	(304)	130
Asset removal costs	(338)	(470)	132
Deferred transmission costs	173	127	46
Deferred generation costs	209	215	(6)
Deferred distribution costs	240	296	(56)
Contract valuations	91	153	(62)
Storm-related costs	285	353	(68)

Other	17	110	(93)
Net Regulatory Assets included on the Consolidated Balance Sheets	$929	$ 1,014	$ (85)

Regulatory assets that do not earn a current return totaled approximately $100 million and $153 million as of September 30, 2017 and December 31, 2016, respectively, primarily related to storm damage costs and are currently being recovered through rates.

As of September 30, 2017, and December 31, 2016, FirstEnergy had approximately $305 million and $157 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy’s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest payments, dividend payments, and contributions to its pension plan.

FE, and its utility and transmission subsidiaries, expect their existing sources of liquidity to remain sufficient to meet their respective anticipated obligations. In addition to internal sources to fund liquidity and capital requirements for 2017 and beyond, FE and its utility and transmission subsidiaries expect to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through a combination of equity and new long-term debt, in each case, subject to market conditions and other factors. FirstEnergy also expects to issue long-term debt at certain Utilities to, among other things, refinance short-term and maturing long-term debt, subject to market conditions and other factors. FirstEnergy plans to fund a portion of its long-term cash needs, including Regulated Transmission's capital program discussed below, with at least $1.5 billion of equity through 2019, subject to market conditions and other factors.

FirstEnergy’s unregulated subsidiaries, specifically FES and AE Supply, expect to rely on, in the case of AE Supply, internal sources, the unregulated companies' money pool, and proceeds generated from previously disclosed asset sales, subject to closing, and in the case of FES, its current access to the unregulated companies' money pool and a two-year secured line of credit from FE of up to $500 million, as further described below. Additionally, FES subsidiaries have debt maturities of $515 million in 2018, beginning in the second quarter, $48 million of interest and lease payments in December 2017 and $38 million of interest payments in the first quarter of 2018. Although management is exploring options to improve cash flow as well as continuing with efforts to explore legislative or regulatory solutions, these obligations and their impact to liquidity raise substantial doubt about FES’ ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern. The inability to refinance the debt maturities or the lack of clarity regarding the timing and viability of alternative strategies could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under its secured credit facility with FE, (iii) further asset sales or plant deactivations, and/or (iv) seeking protection under U.S. bankruptcy laws. In the event FES seeks such protection, FENOC will likely seek protection under U.S. bankruptcy laws.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the Energizing the Future transmission plan, pursuant to which FirstEnergy plans to invest $4.2 to $5.8 billion in capital investments from 2017 to 2021, and which began as a $4.2 billion investment plan from 2014 through 2017 to upgrade FirstEnergy's transmission system. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,500 mile transmission system, making this a continuing platform for investment in the years beyond 2021.

In alignment with FirstEnergy’s strategy to invest in its Regulated Transmission and Regulated Distribution segments as it transitions to a fully regulated company, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile and maintaining investment grade ratings at its regulated businesses and FE. Specifically, at the regulated businesses, 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 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 subsidiaries to utilize short-term borrowing capacity, which could impact available liquidity. In particular, FES may borrow under its secured credit facility with FE, to the extent available, to refinance debt maturities and mandatory purchase obligations, which would impact available liquidity for FES and FE to the extent FE funds any such borrowings through its bank facility and/or cash. In addition, FE and its subsidiaries expect to continually evaluate any planned financings, which may result in changes from time to time.

As of September 30, 2017, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt. Currently payable long-term debt as of September 30, 2017, included the following:

Currently Payable Long-Term Debt	(In millions)
Unsecured notes	$ 150
FMBs	575
Secured PCRBs	141
Unsecured PCRBs	114
Sinking fund requirements	61
Other notes	35
	$ 1,076

Short-Term Borrowings / Revolving Credit Facilities

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

FirstEnergy had $500 million and $2,675 million of short-term borrowings as of September 30, 2017 and December 31, 2016, respectively. FirstEnergy's available liquidity from external sources as of September 30, 2017 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity [3]
			(In millions)	
FirstEnergy[1]	Revolving	December 2021	$4,000	$ 3,490
FET[2]	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 4,490
		Cash	—	399
		Total	$5,000	$ 4,889

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

(2) Includes FET, ATSI, TrAIL and MAIT.

(3) As disclosed in "Long-term Debt Capacity" below, debt capacity is subject to the consolidated debt to total capitalization limits of each borrower as defined under each of the Facilities. As of September 30, 2017, FE and its subsidiaries could issue additional debt of approximately $4.8 billion and remain within the limitations of the financial covenants required by the FE Facility.

FES had $186 million and $101 million of short-term borrowings as of September 30, 2017 and December 31, 2016, respectively. Of such amounts, $102 million and $101 million, respectively, represents a currently outstanding promissory note due April 2, 2018 payable to AE Supply with any additional short-term borrowings representing borrowings under the unregulated companies' money pool. In addition to its access to the unregulated companies' money pool, FES' available liquidity as of September 30, 2017 was as follows:

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

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of September 30, 2017:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)			
FE	$4,000	$ —	$ —	(1)
FET	—	1,000	—	(1)
OE	500	—	500	(2)
CEI	500	—	500	(2)
TE	500	—	500	(2)
JCP&L	600	—	500	(2)
ME	300	—	500	(2)
PN	300	—	300	(2)
WP	200	—	200	(2)
MP	500	—	500	(2)
PE	150	—	150	(2)
ATSI	—	500	500	(2)
Penn	50	—	100	(2)
TrAIL	—	400	400	(2)
MAIT	—	400	400	(2)

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

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

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

As of September 30, 2017, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants as well as in the case of FE, the minimum interest coverage ratio requirement, in each case as defined under the respective Facilities.

Separately, in December 2016, FE and FES entered into a two-year secured credit facility in which FE provides a committed line of credit to FES of up to $500 million and additional credit support of up to $200 million to cover a $169 million surety bond for the benefit of the PA DEP with respect to LBR. As of September 30, 2017, an additional $31 million of surety credit support remains available to FES from FE. So long as FES remains in the unregulated companies' money pool, the $500 million secured line of credit provides FES the needed liquidity in order for FES to satisfy its nuclear support obligation to NG in the event of extraordinary circumstances with respect to its nuclear facilities. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million). Additionally, FES maintains access to the unregulated companies' money pool and continues to conduct its ordinary course business under that money pool in lieu of borrowing under the new facility.

Term Loans

FE has a $1.2 billion variable rate syndicated term loan credit agreement with a maturity date of December 6, 2021. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan refinanced terminated term loan facilities. Additionally, in February 2017, FE entered into two separate $125 million three-year term loan credit agreements with two banks providing for variable rate term loans with a maturity date of February 16, 2020. The proceeds from these term loans reduced borrowings under the FE Facility. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio and interest coverage requirements.

As of September 30, 2017, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants as well as the interest coverage ratio requirement, as defined under these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. Similar but separate arrangements exist among FirstEnergy's unregulated companies. FESC administers these money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through such pool. The average interest rate for borrowings in the first nine months of 2017 was 1.51% per annum for the regulated companies' money pool and 2.44% per annum for the unregulated companies' money pool.

As discussed above, FES currently maintains access to the unregulated companies' money pool in lieu of borrowing under its $500 million secured line of credit. FE expects to provide ongoing access to FES to the unregulated companies' money pool to allow time to evaluate its strategic alternatives including, among other things, the results of legislative and regulatory solutions, including the NOPR released by the Secretary of Energy and action by FERC. As of September 30, 2017, FES, and its subsidiaries, and FENOC had $67 million of net borrowings in the aggregate under the unregulated companies' money pool. Cash flow from operations at FES is expected to be sufficient to fund capital expenditures, nuclear fuel purchases, and repay money pool borrowings through March 2018.

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 September 30, 2017:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody's	Fitch	S&P	Moody's	Fitch
FE	—	—	—	BB+	Baa3	BBB-
FES	CCC+	B1	—	CCC-	Caa1	C
AE Supply	BB	—	BB	BB-	B1	BB-
AGC	—	—	—	BB-	Baa3	BB
ATSI	—	—	—	BBB-	Baa1	BBB+
CEI	BBB+	Baa1	A-	BBB-	Baa3	BBB+
FET	—	—	—	BB+	Baa2	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	A3	BBB+
MAIT	—	—	—	BBB-	Baa1	—
MP	BBB+	A3	BBB+	—	—	—
OE	BBB+	A2	A-	BBB-	Baa1	BBB+
PN	—	—	—	BBB-	Baa1	BBB+
Penn	—	A2	A-	—	—	—
PE	—	—	—	—	—	—
TE	BBB+	Baa1	A-	—	—	—
TrAIL	—	—	—	BBB-	A3	BBB+
WP	BBB+	A1	A-	—	—	—

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of September 30, 2017, FE and its subsidiaries could issue additional debt of approximately $4.8 billion or incur a $2.6 billion reduction to equity, and remain within the limitations of the financial covenants required by the FE Facility.

Changes in Cash Position

As of September 30, 2017, FirstEnergy had $399 million of cash and cash equivalents compared to $199 million of cash and cash equivalents as of December 31, 2016. As of September 30, 2017 and December 31, 2016, FirstEnergy had approximately $36 million and $61 million, respectively, of restricted cash included in Other current assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

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

Net cash provided from operating activities was $2,762 million during the first nine months of 2017 compared with $2,592 million provided from operating activities during the first nine months of 2016. Key changes in cash flows from operations in the first nine months of 2017, compared with the same period of 2016, primarily were as follows:

- the absence of $297 million contribution to the qualified pension plan in 2016;
- higher distribution services retail receipts reflecting implementation of approved rates in Ohio, Pennsylvania and New Jersey, as further described above; partially offset by,
- lower receipts from a decrease in capacity revenue and retail sales at CES.

Cash Flows From Financing Activities

In the first nine months of 2017, cash used for financing activities was $381 million compared to $304 million of cash provided from financing activities during the first nine months of 2016. The following table summarizes new debt financing, redemptions, repayments, short-term borrowings and dividends:

Securities Issued or Redeemed / Repaid	For the Nine Months Ended September 30 2017	2016
	(In millions)	
New Issues		
Term Loan	$250	$—
PCRBs	—	471
Unsecured notes	3,450	—
FMBs	350	50
	$4,050	$521
Redemptions / Repayments		
PCRBs	(158)	(483)
Unsecured notes	(1,330)	(300)
FMBs	(150)	(145)
Senior secured notes	(73)	(89)
	$(1,711)	$(1,017)
Short-term borrowings (repayments), net	$(2,175)	$1,275
Common stock dividend payments	$(478)	$(458)

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

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

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

On June 1, 2017, FG repurchased approximately $130 million of PCRBs, which were subject to a mandatory put on such date. FG is currently holding these PCRBs for remarketing subject to future market and other conditions.

On June 21, 2017, FE issued the aggregate principal amount of $3 billion of its senior notes in three series: $500 million of 2.85% notes due 2022; $1.5 billion of 3.90% notes due 2027; and $1 billion of 4.85% notes due 2047. Proceeds from the issuance of the notes were used: (i) to redeem $650 million of FE's 2.75% notes due in 2018 on July 25, 2017 and (ii) for general corporate purposes, including the repayment of short-term borrowings under the FE Facility.

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

On September 8, 2017, PN issued $300 million of 3.25% senior notes maturing in 2028. Proceeds from the issuance of the notes were used: (i) to repay short-term borrowings and (ii) for working capital needs and other general business purposes.

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

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

Cash Flows From Investing Activities

Cash used for investing activities in the first nine months of 2017 principally represented cash used for property additions. The following table summarizes investing activities for the first nine months of 2017 and the comparable period of 2016:

Cash Used for Investing Activities	For the Nine Months Ended September 30 2017	2016	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$854	$809	$ 45
Regulated Transmission	717	824	(107)
Competitive Energy Services	233	492	(259)
Corporate / Other	43	31	12
Nuclear fuel	156	195	(39)
Investments	72	76	(4)
Asset removal costs	130	101	29
Other	(24)	(52)	28
	$2,181	$2,476	$ (295)

Cash used for investing activities for the first nine months of 2017 decreased $295 million, compared to the same period of 2016, primarily due to lower property additions. The decline in property additions were due to the following:

- a decrease of $259 million at CES, resulting from lower capital investments associated with outages, MATS compliance and the Mansfield dewatering facility,
- a decrease of $107 million at Regulated Transmission due to timing of capital investments associated with its Energizing the Future investment program; partially offset by,
- an increase of $45 million at Regulated Distribution due to an increase in storm restoration work and smart meter investments in Pennsylvania.

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 September 30, 2017, was approximately $3.3 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts(1)	$ 5
Deferred compensation arrangements(2)	568
Fuel Related(3)	72
Other(4)	4
	649
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts(5)	265
FES' guarantee of FG's sale and leaseback obligations	1,600
	1,865
FE's Guarantees on Behalf of Business Ventures	
Global Holding facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries(6)	177
Surety Bonds	212
Sale leaseback indemnity	58
LOCs(7)	10
	457
Total Guarantees and Other Assurances	$ 3,271

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

(2) CES-related portion is $143 million, including $56 million and $87 million at FES and FENOC, respectively.

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

(4) Includes guarantees of $1 million for railcar leases and $3 million for various leases.

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

(6) FE provides credit support for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR. As of September 30, 2017, an additional $31 million of surety credit support remains available to FES from FE under this facility.

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

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG and NG would have claims against each of FES, FG and NG, regardless of whether their primary obligor is FES, FG or NG.

Collateral and Contingent-Related Features

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on CES' power portfolio exposure as of September 30, 2017, FES has posted collateral of $128 million and AE Supply has posted collateral of $2 million. The Regulated Distribution Segment has posted collateral of $3 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of September 30, 2017.

Potential Collateral Obligations	FES	AE Supply	Regulated	FE Corp	Total
		(In millions)			
Contractual Obligations for Additional Collateral					
At Current Credit Rating	$6	$ 2	$ —	$—	$8
Upon Further Downgrade	—	—	42	—	42
Surety Bonds (Collateralized Amount)[(1)]	48	24	105	185	362
Total Exposure from Contractual Obligations	$54	$ 26	$ 147	$185	$412

[(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 $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of September 30, 2017, FES has $2 million of collateral posted with its affiliates.

Other Commitments and Contingencies

FE is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the facility.

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

OFF-BALANCE SHEET ARRANGEMENTS

FES has obligations that are not included on its Consolidated Balance Sheet related to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements (expiring in 2040), which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $873 million as of September 30, 2017. From time to time FirstEnergy and FES enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all. As of September 30, 2017, FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

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

MARKET RISK INFORMATION

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

Commodity Price Risk

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

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 7, "Fair Value Measurements," of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative assets and liabilities as of September 30, 2017 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2017	2018	2019	2020	2021	Thereafter	Total
	(In millions)						
Other external sources[1]	$—	$(19)	$(36)	$(12)	$ —	$ —	$(67)
Prices based on models	(2)	3	—	—	—	—	1
Total[2]	$(2)	$(16)	$(36)	$(12)	$ —	$ —	$(66)

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

(2) Includes $(92) million in non-hedge derivative contracts that are primarily related to NUG contracts at certain of the Utilities. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of September 30, 2017, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $6 million during the next twelve months.

Equity Price Risk

As of September 30, 2017, the FirstEnergy pension plan assets were allocated approximately as follows: 41% in equity securities, 36% in fixed income securities, 9% in absolute return strategies, 9% in real estate, 1% in private equity, and 4% 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. During the nine months ended September 30, 2017, FirstEnergy made no contributions to its qualified pension plan. See Note 3, "Pension and Other Postemployment Benefits," of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. Through September 30, 2017, FirstEnergy's pension plan assets earned approximately 12.5% as compared to an annual expected return on plan assets of 7.5%.

As of September 30, 2017, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through September 30, 2017 FirstEnergy's OPEB plans have earned approximately 8.6% as compared to an annual expected return on plan assets of 7.5%.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of September 30, 2017, approximately 56% of the funds were invested in fixed income securities, 40% of the funds were invested in equity securities and 4% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,490 million, $1,045 million and $112 million for fixed income securities, equity securities and short-term investments, respectively, as of September 30, 2017, excluding $(15) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $105 million reduction in fair value as of September 30, 2017. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy’s NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the nine months ended September 30, 2017, FirstEnergy made no contributions to the NDTs.

Interest Rate Risk

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year. 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 of December 31 and the difference between expected and actual returns on the plans' assets. FirstEnergy would anticipate a pre-tax mark-to-market loss (net of amounts capitalized) to be in the range of approximately $40 million to $260 million assuming a discount rate of approximately 4.00% to 3.75% for the pension plans and 3.75% to 3.50% for the OPEB plans, respectively, and a return on the pension and OPEB plans' assets of 12.5% and 8.6%, respectively, based on actual investment performance through September 30, 2017.

CREDIT RISK

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

Wholesale Credit Risk

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

Retail Credit Risk

FirstEnergy's principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

OUTLOOK

STATE REGULATION

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

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third-party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption and demand and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the goal of 0.97% savings achieved under PE's current plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. The costs of the 2015-2017 plan are expected to be approximately $70 million, of which approximately $56 million was incurred through September 30, 2017. PE filed its 2018-2020 EmPOWER plan on August 31, 2017. The 2018-2020 plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. The MDPSC will consider the 2018-2020 plan in hearings scheduled to begin on October 25, 2017, with a decision expected by December 31, 2017. PE recovers program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE.

On February 27, 2013, the MDPSC issued an order requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 2013 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 2013 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting, as well as the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the Maryland utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On September 26, 2016, the MDPSC initiated a new proceeding to consider an array of issues relating to electric distribution system design, including matters relating to electric vehicles, distributed energy resources, advanced metering infrastructure, energy storage, system planning, rate design, and impacts on low-income customers. Initial comments in the proceeding were filed on October 28, 2016, and the MDPSC held an initial hearing on the matter on December 8-9, 2016. On January 31, 2017, the MDPSC issued a notice establishing five working groups to address these issues over the following eighteen months, and also directed the retention of an outside consultant to prepare a report on costs and benefits of distributed solar generation in Maryland.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third-party EGS and for customers of third-party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended to improve service and benefit customers by supporting equipment maintenance, tree trimming, and inspections of lines, poles and substations, while also compensating for other business and operating expenses. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L’s 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases, the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the generic CTA proceeding to the Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On October 20, 2017, the NJBPU directed its staff to begin a formal rulemaking process to modify its CTA methodology.

OHIO

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

ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024. Other material terms of ESP IV include: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016 and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates (which filing was made on April 3, 2017 and remains pending).

Several parties, including the Ohio Companies, filed applications for rehearing regarding the Ohio Companies' ESP IV with the PUCO. The Ohio Companies' application for rehearing challenged, among other things, the PUCO's failure to adopt the Ohio Companies' suggested modifications to Rider DMR. The Ohio Companies had previously suggested that a properly designed Rider DMR would be valued at $558 million annually for eight years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio. Other parties' applications for rehearing argued, among other things, that the PUCO's adoption of Rider DMR is not supported by law or sufficient evidence. On August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies' challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO's August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the Ohio Manufacturer's Association Energy Group filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. For additional information, see "FERC Matters - Ohio ESP IV PPA" below.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. Starting in 2017, ORC 4928.66 requires the energy savings benchmark to increase by 1% and the peak demand reduction benchmark to increase by 0.75% annually thereafter through 2020 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. On April 15, 2016, the Ohio Companies filed an application for approval of their three-year energy efficiency portfolio plans for the period from January 1, 2017 through December 31, 2019. The plans as proposed comply with benchmarks contemplated by ORC 4928.66 and provisions of the ESP IV, and include a portfolio of energy efficiency programs targeted to a variety of customer segments, including residential customers, low income customers, small commercial customers, large commercial and industrial customers and governmental entities. On December 9, 2016, the Ohio Companies filed a Stipulation and Recommendation with several parties that contained changes to the plan and a decrease in the plan costs. The Ohio Companies anticipate the cost of the plans will be approximately $268 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies' existing rate mechanisms. The hearings were held in January 2017.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, except that in 2014 SB310 froze 2015 and 2016 at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. Oral argument on this matter was held on June 21, 2017.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers. On January 13, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing. On March 29, 2017, the PUCO issued a Second Entry on Rehearing that granted, in part, the applications for rehearing filed by FES and other parties, finding that the PUCO’s guidelines regarding fixed-price contracts should not apply to large mercantile customers. This finding changes the original order, which applied the guidelines to all customers, including mercantile customers. The PUCO also reaffirmed several provisions of the original order, including that the fixed-price guidelines only apply on a going-forward basis and not to existing contracts and that regulatory-out clauses in contracts are permissible.

PENNSYLVANIA

The Pennsylvania Companies operate under DSPs for the June 1, 2017 through May 31, 2019 delivery period, which provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the DSPs, the supply will be provided by wholesale suppliers through a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. The DSPs include modifications to the Pennsylvania Companies’ POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

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

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies’ historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, with expected costs up to $390 million, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order with full recovery through the reconcilable EE&C riders.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the five-year period of 2016 to 2020, as modified, are: WP $88.3 million; PN $60.0 million; Penn $58.9 million; and ME $51.6 million.

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

WEST VIRGINIA

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

On September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. On October 6, 2017, MP and PE proposed an annual decrease in their EE&C rates, effective January 1, 2018, which is not expected to be material to FirstEnergy.

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

On December 30, 2015, MP and PE filed an IRP with the WVPSC identifying a capacity shortfall starting in 2016 and exceeding 700 MWs by 2020 and 850 MWs by 2027. On June 3, 2016, the WVPSC accepted the IRP. On December 16, 2016, MP issued an RFP to address its generation shortfall, along with issuing a second RFP to sell its interest in Bath County. Bids were received by an independent evaluator in February 2017 for both RFPs. AE Supply was the winning bidder of the RFP to address MP’s generation shortfall and on March 6, 2017, MP and AE Supply signed an asset purchase agreement for MP to acquire AE Supply's Pleasants Power Station (1,300 MW) for approximately $195 million, subject to customary and other closing conditions, including regulatory approvals. In addition, on March 7, 2017, MP and PE filed an application with the WVPSC and MP and AE Supply filed an application with FERC requesting authorization for such purchase. The WVPSC held an evidentiary hearing commencing on September 26, 2017, and public hearings were held on September 6, 11, and 12, 2017. An order is anticipated by early 2018. On June 27, 2017, FERC issued a deficiency letter requesting additional information to facilitate FERC's review of the transaction. MP responded to the deficiency letter on July 18, 2017, and to related protests and comments on August 28, 2017. The applications remain pending before the WVPSC and FERC, respectively. With respect to the Bath County RFP, MP does not plan to move forward with that sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

On September 1, 2017, MP and PE filed with the WVPSC for a reconciliation of their VMS to confirm that rate recovery matches VMP costs and for a regular review of that program. MP and PE proposed a $15 million annual decrease in VMS rates effective January 1, 2018, and an additional $15 million decrease in rates for 2019. This is an overall decrease in total revenue and average rates of 1%.

RELIABILITY MATTERS

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

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

FERC MATTERS

Ohio ESP IV PPA

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

ESP IV PPA on April 1, 2016, but subsequently agreed to suspend it and advised FERC of this course of action.

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

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for certain transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June

25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. On June 15, 2016, various parties, including ATSI and the Utilities, filed a settlement agreement at FERC agreeing to apply a combined usage based/socialization approach to cost allocation for charges to transmission customers in the PJM Region for transmission projects operating at or above 500 kV. Certain other parties in the proceeding did not agree to the settlement and filed protests to the settlement seeking, among other issues, to strike certain of the evidence advanced by FirstEnergy and certain of the other settling parties in support of the settlement, as well as provided further comments in opposition to the settlement. FirstEnergy and certain of the other parties responded to such opposition. The settlement is pending before FERC.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On March 17, 2016, FERC denied FirstEnergy's request for rehearing of FERC's earlier order rejecting the settlement agreement and affirmed its prior ruling that ATSI must submit the cost/benefit analysis.

Separately, ATSI resolved a dispute regarding responsibility for certain costs for the “Michigan Thumb” transmission project. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain U.S. appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which FERC denied on May 19, 2016. The MISO TOs subsequently filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened and participated in the proceedings on behalf of ATSI, the Ohio Companies and PP. On June 21, 2017, the Sixth Circuit issued its decision denying the MISO TOs' appeal request. September 19, 2017 was the deadline for MISO and the MISO TOs to seek review by the U.S. Supreme Court. They did not file for review, effectively resolving the dispute over the "Michigan Thumb" transmission project. On a related issue, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

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

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

MAIT Transmission Formula Rate

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

JCP&L Transmission Formula Rate

On October 28, 2016, after withdrawing its request to the NJBPU to transfer its transmission assets to MAIT, JCP&L submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective January 1, 2017. A group of intervenors, including the NJBPU and New Jersey Division of Rate Counsel, filed a protest of the proposed JCP&L transmission rate. Among other things, the protest asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. On March 10, 2017, FERC issued an order accepting the JCP&L formula transmission rate for filing, suspending it for five months, and establishing hearing and settlement judge procedures. On April 10, 2017, JCP&L requested rehearing of FERC’s decision to suspend the effective date of the formula rate. FERC's order on rehearing remains pending. JCP&L’s rates went into effect on June 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. The settlement process is ongoing.

DOE NOPR: Grid Reliability and Resilience Pricing, FERC Docket No. RM18-1

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

FERC is not required to adopt the rules proposed by the DOE in the NOPR. FERC could take other actions as it deems fit pursuant to its statutory authority. On October 2, 2017, FERC established a docket and requested comments on the NOPR. On October 23, 2017, FESC and certain of its affiliates submitted comments. Reply comments are due November 7, 2017. At this time, we are uncertain as to the potential impact that final rules adopted by FERC, if any, would have on FES and our strategic options, and the timing thereof, with respect to the competitive business.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017 and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers commented on the compliance filing, alleging inaccuracies in and lack of transparency of data and information in the compliance filing, and requested that PATH be directed to recalculate the refund provided in the filing. PATH responded to these comments in a filing that was submitted on May 22, 2017. On July 27, 2017, FERC Staff issued a letter to PATH requesting additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH filed its response on September 27, 2017.

FERC orders on PATH's requests for rehearing and compliance filing remain pending.

Market-Based Rate Authority, Triennial Update

The Utilities, AE Supply, FES and its subsidiaries, Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 23, 2016, FESC, on behalf of its affiliates with market-based rate authority, submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. On July 27, 2017, FERC accepted the triennial filing as submitted.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition.

Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA’s regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Various states and other stakeholders appealed the CSAPR update rule to the D.C. Circuit in November and December 2016. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, EPA’s reconsideration of the CSAPR update rule and how EPA and the states ultimately implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's and FES' operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but the EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. The EPA missed the October 1, 2017 deadline and has not yet promulgated the attainment designations. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State Delaware's CAA Section 126 petition by six months to April 7, 2017 but has not taken any further action. In November 2016, the State of Maryland filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 36 EGUs, including Harrison Units

1, 2 and 3, Mansfield Unit 1 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition seeks NOx emission rate limits for the 36 EGUs by May 1, 2017. On January 3, 2017, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to July 15, 2017 but has not taken any further action. On September 27, 2017 and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the U.S. District Court for the District of Maryland seeking an order that EPA either approve or deny the CAA Section 126 petition of November 16, 2016. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

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

On August 3, 2015, FG, a wholly owned subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure event that excuses FG’s performance under its coal transportation contract with these parties. Specifically, the dispute arose from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, all plants covered by this contract were deactivated by April 16, 2015. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG’s declaration of a force majeure under the contract is not valid and seeking damages under the contract through 2025. On May 31, 2016, the parties agreed to a stipulation that if FG’s force majeure defense is determined to be wholly or partially invalid, liquidated damages are the sole remedy available to BNSF and CSX. The arbitration panel consolidated the claims and held a hearing in November and December 2016. On April 12, 2017, the arbitration panel ruled on liability in favor of BNSF and CSX. In the liability award, the panel found, among other things, that FG’s demand for declaratory judgment that force majeure excused FG’s performance was denied, that FG breached and repudiated the coal transportation contract and that the panel retains jurisdiction of claims for liquidated damages for the years 2015-2025. On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to this consolidated proceeding on the terms and conditions set forth below. Pursuant to the settlement agreement, FG will pay CSX and BNSF an aggregate amount equal to $109 million which is payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provides that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. Further, FE and FG, and CSX and BNSF, agreed to release, waive and discharge each other from any further obligations under the claims covered by the settlement agreement upon payment in full of the settlement amount. Until such time, CSX and BNSF will retain the claims covered by the settlement agreement and in the event of a bankruptcy proceeding with respect to FG, to the extent the remaining settlement payments are not paid in full by FG or FE, CSX and BNSF shall be entitled to seek damages for such claims in an amount to be determined by the arbitration panel or otherwise agreed by the parties.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS, which are the counterparties to the coal transportation contract covering the delivery of 2.5 million tons annually through 2025, for FG’s coal-fired Bay Shore Units 2-4, deactivated on September 1, 2012, as a result of the EPA’s MATS and for FG’s W.H. Sammis generating station. The demand for arbitration was submitted to the AAA office in Washington, D.C. against FG alleging, among other things, that FG breached the agreement in 2015 and 2016 and repudiated the agreement for 2017-2025. The counterparties are seeking, among other things, damages, including lost profits through 2025, and a declaratory judgment that FG's claim of force majeure is invalid. The arbitration hearing is scheduled for June 2018. The parties have exchanged settlement proposals to resolve all claims related to this proceeding and all remaining claims. FirstEnergy and FES recorded a pre-tax charge of $55 million in the first quarter of 2017 based on an estimated settlement. If the dispute with BNSF and NS is not settled, the amount of damages owed to BNSF and NS could be materially higher and may cause FES to seek protection under U.S. bankruptcy laws. Absent a settlement, FG intends to vigorously assert its position in this arbitration proceeding, and if it were ultimately determined that the force majeure provisions or other defenses do not excuse the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

As to a specific coal supply agreement, AE Supply, the party thereto, asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, on January 15, 2015, Tunnel Ridge, LLC, the coal supplier, commenced litigation in the Court of Common Pleas of Allegheny County, Pennsylvania alleging AE Supply did not have sufficient justification to terminate the agreement and seeking damages for the difference between the market and contract price of the coal, or lost profits plus incidental damages. AE Supply filed an answer denying any liability related to the termination. On May 1, 2017, the complaint was amended to add FE, FES and FG, although not parties to the underlying contract, as defendants and to seek additional damages based on new claims of fraud, unjust enrichment, promissory estoppel and alter ego. On June 27, 2017, after oral argument, defendants' preliminary objections to the amended complaint were denied. FE, FES, FG and AE Supply believe the merits of this case are distinguishable from the rail arbitration proceedings above based on the contract terms and other elements of the case. There were approximately 5.5 million tons remaining under the contract for delivery. This matter is in the discovery phase of litigation and no trial date has been established. FE, FES, FG and AE Supply dispute the allegations and intend to vigorously defend the merits of the lawsuit. At this time, FE, FES, FG and AE Supply cannot estimate the loss or range of loss regarding the ongoing litigation with respect to this agreement. Damages, if any, are yet to be determined, but an adverse outcome could be material.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, March 27, 2013 and October 18, 2016, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

FirstEnergy has established a goal to reduce CO_2 emissions by 90% below 2005 levels by 2045. There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

The EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act” in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. The EPA released its final CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA’s state specific CO_2 emission rate goals. The EPA’s CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2016, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. On March 28, 2017, an executive order, entitled “Promoting Energy Independence and Economic Growth,” instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be material.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide GHG emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement was ratified by the requisite number of countries (i.e., at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require material capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to

FirstEnergy's operations.

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

On September 30, 2015, the EPA finalized new, more stringent effluent limits for the Steam Electric Power Generating category (40 CFR Part 423) for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, any changes in timing and closure plan requirements in the future, including changes resulting from the strategic review at CES, could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The CCRs from the Bruce Mansfield plant are being beneficially reused with the majority used for reclamation of a site owned by the Marshall County Coal Company in Moundsville, W. Va. and the remainder recycled into drywall by National Gypsum. These beneficial reuse options should be sufficient for ongoing plant operations, however, the Bruce Mansfield plant is pursuing other options. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On September 14, 2017, the Sierra Club's Notices of Appeal before the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility were resolved through a Consent Adjudication between FG, PA DEP and the Sierra Club requiring operational changes, which is subject to a thirty-day comment period with final approval expected in November 2017.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of September 30, 2017 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $131 million have been accrued through September 30, 2017. Included in the total are accrued liabilities of approximately $84 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of September 30, 2017, FirstEnergy had approximately $2.6 billion (FES $1.8 billion) invested in external trusts to be used for the decommissioning and environmental remediation of its nuclear generating facilities. The values of FirstEnergy's NDTs also fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs.

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

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. Although a majority of the necessary modifications and evaluations at FirstEnergy’s nuclear facilities have been completed, some still remain subject to regulatory review or approval.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units, have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. So long as FES remains in the unregulated companies’ money pool, the $500 million secured line of credit with FE discussed in Note 1, "Organization and Basis of Presentation - Going Concern at FES" above provides FES the needed liquidity in order for FES to satisfy its nuclear support obligations to NG.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 10, "Regulatory Matters" of the Combined Notes to Consolidated Financial Statements.

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

ASSET IMPAIRMENT

Competitive Generation Asset Sale

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement (which was subsequently amended and restated as described below) to sell four of AE Supply’s natural gas generating plants and approximately 59% of AGC’s interest in the Bath County pumped hydro facility (1,572 MWs of combined capacity) to a subsidiary of LS Power for an all-cash purchase price of $925 million, subject to customary and other closing conditions, including receipt of regulatory approvals from FERC and the VSCC, as applicable, and various third-party consents. On February 17, 2017, AE Supply and AGC submitted a filing with FERC and on June 13, 2017, FERC issued an order authorizing such transaction as described in the January 2017 asset purchase agreement. On September 29, 2017, the parties filed a request with FERC for authorization to transfer the related hydroelectric license for Bath County under Part I of the FPA. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once all regulatory approvals are obtained. Additionally, the consent of VEPCO is needed for the sale of AGC’s interest in the Bath County pumped hydro facility, as well as agreement among AGC, LS Power and VEPCO with respect to certain amendments to the Bath County project agreements.

On August 30, 2017, the parties, along with AE Supply's subsidiary BU Energy, executed an amended and restated asset purchase agreement to (1) reduce the purchase price to $825 million, subject to adjustments, (2) add BU Energy’s 50% interest in a joint venture that owns the Buchanan Generating Facility (43 MWs) to the transaction and (3) provide that each component of the transaction (i.e., the AE Supply natural gas facilities, AGC’s interest in the Bath County hydroelectric power station and BU Energy’s interest in the Buchanan Generating Facility) may close independently. The sale of the AE Supply natural gas generating plants is expected to close in the fourth quarter of 2017 and the sale of approximately 59% of AGC’s interests in the Bath County hydroelectric power station and BU Energy’s 50% interest in the Buchanan Generating Facility are expected to close in the first quarter of 2018, subject in each case to various customary and other closing conditions including, without limitation, receipt of regulatory approvals and third-party consents, including the consent of VEPCO as discussed above. Under the amended and restated purchase agreement, AE Supply has agreed to satisfy and discharge all of its approximately $305 million of currently outstanding senior notes, which is expected to require the payment of a “make-whole” premium currently estimated to be approximately $100 million based on current interest rates, upon both (i) the consummation of the sale of the natural gas generating plants and (ii) either (a) the consummation of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station or (b) the consummation of the pending sale of the Pleasants Power Station by AE Supply to its affiliate, MP. As a further condition to closing, FE will provide the purchaser two limited three-year guarantees of certain obligations of AE Supply and AGC arising under the amended and restated purchase agreement. On September 29, 2017, the parties filed an application with FERC for authorization to complete the Buchanan Generating Facility sale. On October 20, 2017, the parties filed an application with the VSCC for approval of the sale of approximately 59% of AGC's interest in the Bath County hydroelectric power station. There can be no assurance that all regulatory approvals will be obtained and/or all closing conditions will be satisfied or that any of the transactions will be consummated.

As a result of the amended asset purchase agreement, CES recorded non-cash pre-tax impairment charges of $158 million in the nine-month period ended September 30, 2017.

NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Pronouncements

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

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

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB 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 or in the 2016 Annual Report on Form 10-K based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting. Below is an update to the discussion of pronouncements contained in the 2016 Annual Report on Form 10-K.

ASU 2014-09, "Revenue from Contracts with Customers" (Issued May 2014 and subsequently updated to address implementation questions): For public business entities, the new revenue recognition guidance will be effective for annual and interim reporting periods beginning after December 15, 2017. FirstEnergy will not early adopt the standard. FirstEnergy has evaluated its revenues and expects limited impacts to current revenue recognition practices.

FirstEnergy expects to apply the new guidance on a modified retrospective basis and continues to assess the impact on its financial statements and disclosures.

ASU 2016-02, "Leases (Topic 842)" (Issued February 2016): ASU 2016-02 will require organizations that lease assets with lease terms of more than 12 months to recognize assets and liabilities for the rights and obligations created by those leases on their balance sheets. In addition, new qualitative and quantitative disclosures of the amounts, timing, and uncertainty of cash flows arising from leases will be required. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. Lessors and lessees will be required to apply a modified retrospective transition approach, which requires adjusting the accounting for any leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. Any leases that expire before the initial application date will not require any accounting adjustment.

ASU 2017-01, "Business Combinations: Clarifying the Definition of a Business" (Issued January 2017): ASU 2017-01 assists entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. The ASU will be applied prospectively to any transactions occurring within the period of adoption. Early adoption is permitted, including for interim or annual periods in which the financial statements have not been issued or made available for issuance.

ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (Issued March 2017): ASU 2017-07 requires entities to retrospectively (1) disaggregate the current-service-cost component from the other components of net benefit cost (the “other components”) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. In addition, only service costs are eligible for capitalization on a prospective basis. Because the non-service cost components of net benefit cost will no longer be eligible for capitalization after December 31, 2017, FirstEnergy will recognize these components in income as a result of adopting the standard. FirstEnergy is currently evaluating presentation of the Statement of Income and the impact on disclosures as a result of adopting ASU 2017-07. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES, a subsidiary of FE, was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to retail and wholesale customers. FES also owns and operates, through its FG subsidiary, fossil generating facilities and owns, through its NG subsidiary, nuclear generating facilities, which are operated by FENOC. FES purchases the entire output of the generation facilities owned by FG and NG. Prior to April 1, 2016, FES financially purchased the uncommitted output of AE Supply's generation facilities under a PSA. On December 21, 2015, FES agreed, under a PSA, to physically purchase all the output of AE Supply's generation facilities effective April 1, 2016. FES and AE Supply terminated the PSA effective April 1, 2017.

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

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

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

Over the past several years, FES has been impacted by a decrease in demand and excess generation supply in the PJM Region, which has resulted in low power and capacity prices, as well as significant environmental compliance costs. To address this, FES sold or deactivated approximately 2,700 MWs of competitive generation from 2012 to 2015 and announced in 2016 plans to exit and/or deactivate an additional 856 MWs by 2020 related to the Bay Shore Unit 1 generating station and Units 1-4 of the W.H. Sammis generating station. Additionally, FES has continued to focus on cost reductions, including those identified as part of FirstEnergy’s previously disclosed cash flow improvement plan.

However, the energy and capacity markets remain weak with significantly low capacity clearing prices and current forward pricing as well as the long-term fundamental view on energy and capacity prices. In order to focus on stable and predictable cash flow from its regulated business units, in November of 2016, FirstEnergy announced a strategic review of its competitive operations with a target to implement its exit from competitive operations by mid-2018.

The strategic options to exit the competitive operations are still uncertain, but could include one or more of the following:

- legislative or regulatory solutions for generation assets that recognize their environmental or energy security benefits;

- restructuring FES debt with its creditors;
- seeking protection under U.S. bankruptcy laws for FES and likely FENOC; and/or
- additional asset sales and/or plant deactivations.

Furthermore, the implementation of various strategic options, and the timing thereof, could be impacted by various events, including, but not limited to the following:

- The outcome of efforts related to the NOPR released by the Secretary of Energy and action by FERC to address critical issues central to protecting the long-term reliability and resiliency of the electric grid provided by traditional baseload resources, such as coal and nuclear generation;
- The resolution of legislation before the Ohio General Assembly that would create a zero-emission nuclear (ZEN) program that would provide compensation to nuclear power plants for their fuel diversity, environmental and other benefits and the potential for similar legislative action in Pennsylvania; and/or
- The inability to finalize and consummate a settlement agreement with BNSF and NS regarding a previously disclosed long-term coal transportation contract dispute as discussed in "Outlook - Environmental Matters" above, whereby FG could be subject to materially higher damages.

FES continues to be managed conservatively due to the stress of weak energy prices, insufficient results from recent capacity auctions and anemic demand forecasts. Furthermore, the credit quality of FES, specifically the unsecured debt rating of Caa1 at Moody’s, CCC- at S&P and C at Fitch and a negative outlook from Moody's and S&P, has challenged its ability to hedge generation with retail and forward wholesale sales due to significant collateral requirements. As a result, FES' contract sales are expected to decline from 52 million MWHs in 2016 to 40-45 million MWHs in 2017 and to 30-35 million MWHs in 2018. While the reduced contract sales will decrease potential collateral requirements, market price volatility may significantly impact FES' financial results due to the increased exposure to the wholesale spot market.

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of September 30, 2017, its current credit rating and the current forward wholesale pricing environment present significant challenges to FES. Furthermore, an inability to develop and execute upon viable alternative strategies for its competitive portfolio would continue to further stress the liquidity and financial condition of FES.

Cash flow from operations at FES is expected to be sufficient to fund capital expenditures, nuclear fuel purchases, and repay money pool borrowings through March 2018. However, as previously disclosed, FES has $515 million of maturing debt in 2018, beginning in the second quarter. Additionally, FES has $48 million of interest and lease payments in December 2017 and $38 million of interest payments in the first quarter of 2018. Based on FES' current senior unsecured debt rating, capital structure and the forecasted decline in wholesale forward market prices over the next few years, the debt maturities are likely to be difficult to refinance. Furthermore, lack of clarity regarding the timing and viability of alternative strategies, including additional asset sales or deactivations and/or converting generation from competitive operations to a regulated or regulated-like construct in a way that provides FES with the means to satisfy its obligations over the long-term, may also require FES to restructure debt and other financial obligations with its creditors and/or seek protection under U.S. bankruptcy laws. In the event FES seeks protection under U.S. bankruptcy laws, FENOC will likely seek such protection. Although management is exploring capital and other cost reductions, asset sales, and other options to improve cash flow as well as continuing with efforts to explore legislative or regulatory solutions, these obligations and their impact to liquidity raise substantial doubt about FES’ ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern.

For additional information with respect to FES, please see the information contained under "Risk Factors" in Part II, Item 1A of this Form 10-Q and in "FirstEnergy’s Management’s Discussion and Analysis of Financial Condition and Results of Operations" under the following subheadings, which information is incorporated by reference herein: "FirstEnergy's Business," "Executive Summary," "Capital Resources and Liquidity," "Guarantees and Other Assurances," "Off-Balance Sheet Arrangements," "Market Risk Information," "Credit Risk," "New Accounting Pronouncements," and "Outlook."

Results of Operations

Operating results increased $282 million in the first nine months of 2017, compared to the same period of 2016, primarily due to the absence of asset impairment and plant exit costs recognized in 2016, as discussed below, and lower depreciation expense, partially offset by a pre-tax charge of $164 million associated with estimated losses on long-term coal transportation contract disputes, as discussed in "Outlook - Environmental Matters" above, higher non-cash mark-to-market losses on commodity contract positions and lower capacity revenue.

Revenues -

Total revenues decreased $1,003 million in the first nine months of 2017, compared to the same period of 2016, primarily due to lower contract sales volumes at lower rates, lower capacity revenues from lower capacity auction prices, and lower net gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	For the Nine Months Ended September 30 2017	2016	Decrease
	(In millions)		
Contract Sales:			
Direct	$560	$610	$(50)
Governmental Aggregation	303	666	(363)
Mass Market	97	133	(36)
POLR	389	447	(58)
Structured	246	353	(107)
Total Contract Sales	1,595	2,209	(614)
Wholesale	710	1,015	(305)
Transmission	30	53	(23)
Other	63	124	(61)
Total Revenues	$2,398	$3,401	$(1,003)

MWH Sales by Channel	For the Nine Months Ended September 30 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	11,504	11,391	1.0 %
Governmental Aggregation	5,686	10,798	(47.3)%
Mass Market	1,425	1,912	(25.5)%
POLR	6,983	7,526	(7.2)%
Structured	6,398	8,863	(27.8)%
Total Contract Sales	31,996	40,490	(21.0)%
Wholesale	11,134	8,461	31.6 %
Total MWH Sales	43,130	48,951	(11.9)%

The following table summarizes the price and volume factors contributing to changes in revenues in the first nine months of 2017, compared with the same period of 2016:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$6	$(56)	$ —	$ —	$(50)
Governmental Aggregation	(315)	(48)	—	—	(363)
Mass Market	(34)	(2)	—	—	(36)
POLR	(32)	(26)	—	—	(58)
Structured	(100)	(7)	—	—	(107)
Wholesale	73	(4)	(114)	(260)	(305)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract in 2016. The Direct, Governmental Aggregation and Mass Market customer base was approximately 842,000 as of September 30, 2017, compared to 1.4 million as of September 30, 2016. Although unit pricing in Direct, Governmental Aggregation and Mass

Market was lower year-over-year, the decrease was primarily attributable to lower capacity expense as discussed below, which is a component of the retail price.

The decrease in POLR revenue of $58 million was primarily due to lower volumes and lower unit prices. Structured revenue decreased $107 million, primarily due to the impact of lower transaction volumes.

Wholesale revenues decreased $305 million, primarily due to a decrease in capacity revenue from lower capacity auction prices and lower net gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions at slightly lower market prices.

Transmission revenue decreased $23 million, primarily due to lower congestion revenues.

Other revenues decreased $61 million, primarily due to lower lease revenues from the expiration of a nuclear sale-leaseback agreement. FES earned lease revenue associated with the lessor equity interests it has purchased in sale-leaseback transactions, one of which expired in June 2017 and another in May 2016.

Operating Expenses -

Total operating expenses decreased $1,293 million in the first nine months of 2017, compared to the same period of 2016.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first nine months of 2017, compared with the same period of 2016:

	Source of Change Increase (Decrease)				
Operating Expenses	Volumes	Unit Costs	Loss on Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(88)	$ 9	$ (58)	$ —	$(137)
Nuclear Fuel	3	2	—	—	5
Affiliated Purchased Power	(92)	23	(169)	—	(238)
Non-affiliated Purchased Power	(34)	17	(91)	(253)	(361)

Fossil and nuclear fuel costs decreased $132 million, primarily due to the absence of $58 million in settlement and termination costs on coal contracts recognized in 2016, as well as lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as described above, partially offset by higher unit costs.

Affiliated purchased power costs decreased $238 million, primarily resulting from the termination of the AE Supply PSA, effective April 1, 2017, and the expiration of a nuclear sale-leaseback agreement.

Non-affiliated purchased power costs decreased $361 million due to lower capacity expenses ($253 million), reduced net losses on financially settled contracts ($91 million), and lower volumes ($34 million), partially offset by higher unit costs ($17 million). The decrease in capacity expense, which is a component of FES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with FES' retail sales obligation. Lower volumes primarily resulted from lower contract sales as discussed above, partially offset by economic purchases resulting from the low wholesale spot market price environment.

Other operating expenses increased $170 million in the first nine months of 2017, compared to the same period of 2016, due to the following:

- A $164 million charge associated with estimated losses on long-term coal transportation contract disputes was recognized in the first quarter of 2017, as discussed in "Outlook - Environmental Matters" above.

- Fossil operating and maintenance expenses decreased $33 million, primarily due to lower outage costs and the absence of plant demolition costs recognized in 2016.

- Nuclear operating and maintenance expenses increased $18 million, primarily as a result of higher refueling outage costs, partially offset by lower non-outage maintenance costs. There were two refueling outages during the first nine months of 2017, as compared to one refueling outage during the same period of 2016.

- Transmission expenses decreased $49 million, primarily due to lower contract sales volumes.

- Other operating expenses increased $70 million, primarily due to higher non-cash mark-to-market losses on commodity contract positions, partially offset by the absence of a termination charge associated with an FES Governmental Aggregation customer contract.

Depreciation expense decreased $170 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016.

General taxes decreased $22 million, primarily due to lower property taxes and reduced gross receipts taxes associated with lower retail sales volumes.

Impairment of assets decreased $540 million, primarily due to the absence of an impairment of goodwill and a $517 million impairment of Units 1-4 of the W.H. Sammis generating station and the Bay Shore Unit 1 generating station recognized in 2016.

Other Expense —

Total other expense decreased $11 million in the first nine months of 2017, as compared to the same period of 2016, primarily due to higher investment income on NDT investments.

Income Tax Benefits —

FES' effective tax rate for the nine months ended September 30, 2017 and 2016 was 48.3% on pre-tax income and 1.8% on pre-tax losses, respectively. The change in the effective tax rate was primarily due to a $65 million of valuation allowance recognized in 2016 against state and local NOL carryforwards and the impairment of goodwill also recognized in 2016, of which $23 million was non-deductible for tax purposes.

Changes in Cash Position

FES expects to rely on its current access to the unregulated companies' money pool and a two-year secured line of credit from FE of up to $500 million, as further described above. Additionally, FES subsidiaries have debt maturities of $515 million in 2018, beginning in the second quarter. The inability to refinance the debt maturities could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under its credit facility with FE, (iii) further asset sales or plant deactivations, and/or (iv) seeking protection under U.S. bankruptcy laws. In the event FES seeks such protection, FENOC will likely seek protection under U.S. bankruptcy laws.

FES continues to be managed conservatively due to the stress of weak power prices, insufficient proceeds from recent capacity auctions and anemic demand forecasts that have lowered the value of the business. Furthermore, the credit quality of FES, specifically its unsecured debt rating of Caa1 at Moody’s, CCC- at S&P and C at Fitch and a negative outlook from Moody's and S&P, has challenged its ability to hedge generation with retail and forward wholesale sales without collateral obligations, which reduce the business units available liquidity. A lack of viable alternative strategies for its competitive portfolio would continue to further stress the liquidity and financial condition of FES.

As discussed above, FES currently maintains access to the unregulated companies' money pool in lieu of borrowing under its $500 million secured line of credit. FE expects to provide ongoing access to FES to the unregulated companies' money pool to allow time to evaluate its strategic alternatives including, among other things, the results of legislative and regulatory solutions, including the NOPR released by the Secretary of Energy and action by FERC. As of September 30, 2017, FES, and its subsidiaries, and FENOC had $67 million of net borrowings in the aggregate under the unregulated companies' money pool. Cash flow from operations at FES is expected to be sufficient to fund capital expenditures, nuclear fuel purchases, and repay money pool borrowings through March 2018.

Cash Flows From Operating Activities

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

Net cash provided from operating activities was $458 million during the first nine months of 2017 compared with $605 million provided from operating activities during the first nine months of 2016. Cash flows from operations decreased $147 million in the first nine months of 2017, compared with the same period of 2016 primarily due to lower receipts from a decrease in capacity revenues and retail sales, as discussed above in "Results of Operations" and timing of working capital.

Cash Flows From Financing Activities

For the first nine months of 2017, cash used for financing activities was $83 million, compared to cash provided from financing activities of $61 million in same period of 2016. The following table summarizes new debt financing, redemptions, repayments and short-term borrowings:

Securities Issued or Redeemed / Repaid	For the Nine Months Ended September 30 2017	2016
	(In millions)	
New Issues		
PCRBs	$—	$471
Redemptions / Repayments		
Senior secured notes	$(5)	$(20)
PCRBs	(158)	(483)
	$(163)	$(503)
Short-term borrowings, net	$85	$101

Cash Flows From Investing Activities

Cash used for investing activities for the first nine months of 2017 principally represented cash used for property additions and nuclear fuel. The following table summarizes investing activities for the first nine months of 2017 and comparable period of 2016.

Cash Used for Investing Activities	For the Nine Months Ended September 30 2017	2016
	(In millions)	
Property Additions	$201	$432
Nuclear fuel	156	195
Loans to affiliated companies, net	(29)	15
Investments	44	43
Other	3	(19)
	$375	$666

Cash used for investing activity for the first nine months of 2017 decreased $291 million, compared to the same period of 2016, primarily due to lower property additions. Property additions decreased due to lower capital expenditures related to outages and the Mansfield dewatering facility, which was substantially completed in 2016.

Market Risk Information

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

Commodity Price Risk

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

Sources of information for the valuation of commodity derivative assets and liabilities as of September 30, 2017 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2017	2018	2019	2020	2021	Thereafter	Total
	(In millions)						
Other external sources[1]	$10	$15	$ —	$ —	$ —	$ —	$25
Prices based on models	(2)	—	—	—	—	—	(2)
Total	$8	$15	$ —	$ —	$ —	$ —	$23

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

FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of September 30, 2017, an increase in commodity prices of 10% would decrease net income by approximately $6 million during the next twelve months.

Interest Rate Risk

FES' exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates.

Equity Price Risk

NDT funds have been established to satisfy NG's nuclear decommissioning obligations. Included in NG's NDT are fixed income, equities and short-term investments carried at market values of approximately $969 million, $765 million and $96 million, respectively, as of September 30, 2017, excluding $(7) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $76 million reduction in fair value as of September 30, 2017. NG recognizes in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of NG's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements by NG.

Credit Risk

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

Wholesale Credit Risk

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

Retail Credit Risk

FES' principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FES' retail credit risk may be adversely impacted.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “First Energy Corp. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Information” and "FirstEnergy Solutions Corp. Management's Narrative Analysis of Results of Operations - Market Risk Information" in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

(b) Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2017, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FirstEnergy's and FES' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Note 10, "Regulatory Matters," and Note 11, "Commitments, Guarantees and Contingencies," of the Combined Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors discussed in Part I, “Item 1A. Risk Factors” in the Registrants’ Annual Report on Form 10-K for the year ended December 31, 2016, and Part II, "Item 1A. Risk Factors" in the Registrants' Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, which could materially affect the Registrants’ business, financial condition or future results. In addition, you should carefully consider the information set forth in this report, including without limitation, the updated disclosures throughout and the risk factor presented below, which update, and should be read in conjunction with, the above-referenced risk factors and information disclosed in the Registrants’ documents previously filed with the SEC.

In the event of a foreclosure, liquidation, bankruptcy or similar proceeding involving FES, FG or NG, the value of the collateral securing the secured indebtedness of FG and NG may not be sufficient to ensure repayment of such indebtedness and, in the case of a bankruptcy proceeding, the ability of holders of such indebtedness, including FE, to realize any such value may be delayed or otherwise limited

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

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

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

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) FirstEnergy

The table below sets forth information on a monthly basis regarding FirstEnergy's purchases of its common stock during the third quarter of 2017:

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs(2)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs(2)
July 1-31, 2017	—	—	—	—
August 1-31, 2017	2,318	$ 32.62	—	—
September 1-30, 2017	—	—	—	—
Third Quarter	2,318	$ 32.62	—	—

(1) Share amounts reflect shares that were surrendered to FirstEnergy by a participant under our 2007 Incentive Plan to satisfy tax withholding obligations relating to the vesting of a restricted stock award and the subsequent dividend reinvestments on such equity award. The total number of shares repurchased represents the net shares surrendered to FirstEnergy to satisfy tax withholding. All such repurchased shares are now held as treasury shares.

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

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	
FirstEnergy	
(A) 12	Fixed charge ratio
(A) 31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A) 31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended September 30, 2017, formatted in XBRL (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 Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
FES	
(A) 31.1	Certification of principal executive officer, as adopted pursuant to Rule 13a-14(a)
(A) 31.2	Certification of principal financial officer, as adopted pursuant to Rule 13a-14(a)
(A) 32	Certification of principal executive officer and principal financial officer, pursuant to 18 U.S.C. Section 1350
101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended September 30, 2017, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income (Loss) and Comprehensive Income (Loss), (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

(A) Provided herein in electronic format as an exhibit.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, except as set forth above, neither FirstEnergy nor FES have filed as an exhibit to this Form 10-Q 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 each hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

October 26, 2017

FIRSTENERGY CORP.
Registrant

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

FIRSTENERGY SOLUTIONS CORP.
Registrant

/s/ Jason J. Lisowski
Jason J. Lisowski
Controller and Treasurer
(Principal Financial Officer)