FIRSTENERGY CORP
Form 10-Q
July 27, 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 June 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 JUNE 30, 2017
FirstEnergy Corp., $0.10 par value	444,304,456
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 investment plan, 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 DOE study.
- 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 debt and other financial obligations with its creditors or seek protection under U.S. bankruptcy laws and the losses, liabilities and claims arising from such bankruptcy proceeding, including any obligations at FirstEnergy.
- The risks and uncertainties at the CES segment, including FES and its subsidiaries and FENOC, related to continued depressed wholesale energy and capacity markets, and the viability and/or success of strategic business alternatives, such as 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.
- 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 and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of labor disruptions by our unionized workforce.
- The risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks.
- The impact of the regulatory process and resulting outcomes on the matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates.
- 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
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
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
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
ALJ	Administrative Law Judge

GLOSSARY OF TERMS, Continued

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
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
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
GWH	Gigawatt-hour
HB554	Ohio House Bill No. 554

HCl	Hydrochloric Acid
ICE	Intercontinental Exchange, Inc.
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour

GLOSSARY OF TERMS, Continued

LOC	Letter of Credit
LS Power	LS Power Equity Partners III, LP
LSE	Load Serving Entity
LTIIPs	Long-Term Infrastructure Improvement Plans
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master Limited Partnership
mmBTU	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MVP	Multi-Value Project
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOAC	Northwestern Ohio Aggregation Coalition
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
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

GLOSSARY OF TERMS, Continued

REIT	Real Estate Investment Trust
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPM	Reliability Pricing Model
RRS	Retail Rate Stability
RSS	Rich Site Summary
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Service
SB221	Amended Substitute Ohio Senate Bill No. 221
SB310	Substitute Ohio Senate Bill No. 310
SB320	Ohio Senate Bill No. 320
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
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 June 30		For the Six Months Ended June 30	
(In millions, except per share amounts)	2017	2016	2017	2016
REVENUES:				
Regulated Distribution	$2,262	$2,189	$4,752	$4,699
Regulated Transmission	327	275	640	561
Unregulated businesses	720	937	1,469	2,010
Total revenues*	3,309	3,401	6,861	7,270
OPERATING EXPENSES:				
Fuel	343	438	711	819
Purchased power	735	889	1,598	2,013
Other operating expenses	957	964	2,099	1,882
Provision for depreciation	281	334	556	663
Amortization of regulatory assets, net	65	63	124	124
General taxes	253	241	524	521
Impairment of assets (Note 14)	131	1,447	131	1,447
Total operating expenses	2,765	4,376	5,743	7,469
OPERATING INCOME (LOSS)	544	(975)	1,118	(199)
OTHER INCOME (EXPENSE):				
Investment income	17	19	41	47
Interest expense	(290)	(289)	(577)	(577)
Capitalized financing costs	20	26	40	51
Total other expense	(253)	(244)	(496)	(479)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	291	(1,219)	622	(678)
INCOME TAXES (BENEFITS)	117	(130)	243	83
NET INCOME (LOSS)	$174	$(1,089)	$379	$(761)
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:				
Basic	$0.39	$(2.56)	$0.86	$(1.79)
Diluted	$0.39	$(2.56)	$0.85	$(1.79)
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	444	425	443	424

Diluted	445	425	444	424
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$—	$—	$0.72	$0.72

* Includes excise tax collections of $91 million and $92 million in the three months ended June 30, 2017 and 2016, respectively, and $191 million and $199 million in the six months ended June 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)

(In millions)	For the Three Months Ended June 30 2017	2016	For the Six Months Ended June 30 2017	2016
NET INCOME (LOSS)	$174	$(1,089)	$379	$(761)
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(18)	(18)	(36)	(36)
Amortized losses on derivative hedges	1	2	4	4
Change in unrealized gains on available-for-sale securities	(2)	35	14	63
Other comprehensive income (loss)	(19)	19	(18)	31
Income taxes (benefits) on other comprehensive income (loss)	(7)	7	(7)	11
Other comprehensive income (loss), net of tax	(12)	12	(11)	20
COMPREHENSIVE INCOME (LOSS)	$162	$(1,077)	$368	$(741)

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)	June 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$114	$ 199
Receivables-		
Customers, net of allowance for uncollectible accounts of $52 in 2017 and $53 in 2016	1,375	1,440
Other, net of allowance for uncollectible accounts of $1 in 2017 and 2016	161	175
Materials and supplies	553	564
Prepaid taxes	227	98
Derivatives	45	140
Collateral	129	176
Other	151	158
	2,755	2,950
PROPERTY, PLANT AND EQUIPMENT:		
In service	43,929	43,767
Less — Accumulated provision for depreciation	15,999	15,731
	27,930	28,036
Construction work in progress	1,249	1,351
	29,179	29,387
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,588	2,514
Other	507	512
	3,095	3,026
ASSETS HELD FOR SALE (Note 14)	815	—
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	5,618
Regulatory assets	994	1,014
Other	871	1,153
	7,483	7,785
	$43,327	$ 43,148
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$2,015	$ 1,685
Short-term borrowings	225	2,675
Accounts payable	932	1,043
Accrued taxes	518	580
Accrued compensation and benefits	293	363
Derivatives	18	78
Collateral	27	42
Other	619	660
	4,647	7,126
CAPITALIZATION:		
Common stockholders’ equity-		

Common stock, $0.10 par value, authorized 490,000,000 shares - 444,304,456 and 442,344,218 shares outstanding as of June 30, 2017 and December 31, 2016, respectively	44	44
Other paid-in capital	10,272	10,555
Accumulated other comprehensive income	163	174
Accumulated deficit	(4,159)	(4,532)
Total common stockholders' equity	6,320	6,241
Long-term debt and other long-term obligations	20,582	18,192
	26,902	24,433
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	3,992	3,765
Retirement benefits	3,784	3,719
Asset retirement obligations	1,526	1,482
Deferred gain on sale and leaseback transaction	740	757
Adverse power contract liability	152	162
Other	1,584	1,704
	11,778	11,589
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$43,327	$ 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)

	For the Six Months Ended June 30	
(In millions)	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (Loss)	$379	$(761)
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	792	950
Deferred purchased power and other costs	34	(33)
Deferred income taxes and investment tax credits, net	224	72
Impairment of assets (Note 14)	131	1,447
Investment impairments	7	10
Deferred costs on sale leaseback transaction, net	24	24
Retirement benefits, net of payments	17	31
Pension trust contributions	—	(160)
Unrealized loss on derivative transactions (Note 8)	53	5
Lease payments on sale and leaseback transaction	(47)	(94)
Changes in current assets and liabilities-		
Receivables	83	101
Materials and supplies	(10)	(1)
Prepaid taxes and other current assets	(127)	(91)
Accounts payable	—	(22)
Accrued taxes	(62)	(80)
Accrued compensation and benefits	(125)	(50)
Other current liabilities	(55)	16
Collateral, net	32	21
Other	132	87
Net cash provided from operating activities	1,482	1,472
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	3,500	—
Short-term borrowings, net	—	1,225
Redemptions and Repayments-		
Long-term debt	(735)	(581)
Short-term borrowings, net	(2,450)	—
Common stock dividend payments	(319)	(305)
Other	(52)	24
Net cash provided from (used for) financing activities	(56)	363
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,254)	(1,492)
Nuclear fuel	(134)	(188)
Sales of investment securities held in trusts	1,257	1,024
Purchases of investment securities held in trusts	(1,305)	(1,073)

Asset removal costs	(79)	(63)
Other	4	25
Net cash used for investing activities	(1,511)	(1,767)
Net change in cash and cash equivalents	(85)	68
Cash and cash equivalents at beginning of period	199	131
Cash and cash equivalents at end of period	$114	$199

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

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

	For the Three Months Ended June 30		For the Six Months Ended June 30	
(In millions)	2017	2016	2017	2016
STATEMENTS OF INCOME (LOSS)				
REVENUES:				
Electric sales to non-affiliates	$635	$958	$1,403	$1,965
Electric sales to affiliates	80	102	191	249
Other	26	42	61	87
Total revenues	741	1,102	1,655	2,301
OPERATING EXPENSES:				
Fuel	154	228	298	393
Purchased power from affiliates	39	167	202	249
Purchased power from non-affiliates	156	266	316	643
Other operating expenses	286	369	804	609
Provision for depreciation	27	84	52	167
General taxes	18	19	39	45
Impairment of assets (Note 14)	—	540	—	540
Total operating expenses	680	1,673	1,711	2,646
OPERATING INCOME (LOSS)	61	(571)	(56)	(345)
OTHER INCOME (EXPENSE):				
Investment income	15	19	35	32
Miscellaneous income	—	1	5	3
Interest expense — affiliates	(5)	(1)	(7)	(3)
Interest expense — other	(35)	(37)	(70)	(73)
Capitalized interest	6	8	14	18
Total other expense	(19)	(10)	(23)	(23)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	42	(581)	(79)	(368)
INCOME TAXES (BENEFITS)	23	(143)	(18)	(61)
NET INCOME (LOSS)	$19	$(438)	$(61)	$(307)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)				
NET INCOME (LOSS)	$19	$(438)	$(61)	$(307)
OTHER COMPREHENSIVE INCOME:				
Pension and OPEB prior service costs	(4)	(3)	(7)	(7)
Amortized gains on derivative hedges	—	(1)	—	(1)

Change in unrealized gains on available-for-sale securities	6	33	22	56
Other comprehensive income	2	29	15	48
Income taxes on other comprehensive income	—	12	5	19
Other comprehensive income, net of tax	2	17	10	29
COMPREHENSIVE INCOME (LOSS)	$21	$(421)	$(51)	$(278)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 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	185	213
Affiliated companies	385	452
Other	12	27
Notes receivable from affiliated companies	—	29
Materials and supplies	260	267
Derivatives	41	137
Collateral	111	157
Prepaid taxes and other	51	63
	1,047	1,347
PROPERTY, PLANT AND EQUIPMENT:		
In service	7,382	7,057
Less — Accumulated provision for depreciation	6,055	5,929
	1,327	1,128
Construction work in progress	299	427
	1,626	1,555
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,793	1,552
Other	9	10
	1,802	1,562
DEFERRED CHARGES AND OTHER ASSETS:		
Property taxes	20	40
Accumulated deferred income taxes	2,108	2,279
Derivatives	9	77
Other	379	381
	2,516	2,777
	$6,991	$ 7,241
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$255	$ 179
Short-term borrowings - affiliated companies	275	101
Accounts payable-		
Affiliated companies	264	550
Other	91	110
Accrued taxes	129	143
Derivatives	18	77
Other	170	156
	1,202	1,316
CAPITALIZATION:		
Common stockholder's equity-		
	3,730	3,658

Common stock, without par value, authorized 750 shares - 7 shares outstanding as of June 30, 2017 and December 31, 2016		
Accumulated other comprehensive income	79	69
Accumulated deficit	(3,570)	(3,509)
Total common stockholder's equity	239	218
Long-term debt and other long-term obligations	2,573	2,813
	2,812	3,031
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	740	757
Retirement benefits	205	197
Asset retirement obligations (Note 9)	975	901
Derivatives	1	52
Other	1,056	987
	2,977	2,894
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$6,991	$ 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 Six Months Ended June 30	
(In millions)	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(61)	$(307)
Adjustments to reconcile net loss to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel, intangible assets and deferred debt-related costs	157	301
Deferred costs on sale and leaseback transaction, net	24	24
Deferred income taxes and investment tax credits, net	104	(16)
Investment impairments	7	9
Unrealized loss on derivative transactions (Note 8)	53	5
Lease payments on sale and leaseback transaction	(47)	(94)
Impairment of assets (Note 14)	—	540
Changes in current assets and liabilities-		
Receivables	110	110
Materials and supplies	(10)	12
Prepaid taxes and other current assets	12	(13)
Accounts payable	(194)	(79)
Accrued taxes	(14)	2
Other current liabilities	(8)	16
Collateral, net	46	50
Other	116	(3)
Net cash provided from operating activities	295	557
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Short-term borrowings, net	174	210
Redemptions and repayments-		
Long-term debt	(163)	(245)
Other	(4)	(3)
Net cash (used for) provided from financing activities	7	(38)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(169)	(335)
Nuclear fuel	(134)	(188)
Sales of investment securities held in trusts	437	441
Purchases of investment securities held in trusts	(466)	(467)
Cash investments	—	11
Loans to affiliated companies, net	29	11
Other	1	8

Net cash used for investing activities	(302)	(519)
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)

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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 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 24,000 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. 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 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 June 30, 2017 and 2016, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $9 million of allowance for equity funds used during construction and $11 million and $17 million, respectively, of capitalized interest. For each of the six months ended June 30, 2017 and 2016, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $17 million of allowance for equity funds used during construction and $23 million and $34 million, respectively, of capitalized interest.

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 prolonged decrease in demand and excess generation supply in the PJM Region, which has resulted in a period of protracted low power and capacity prices. To address this, CES sold or deactivated more than 6,770 MWs of competitive generation from 2012 to 2015 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 continue to be weak, as evidenced by the significantly depressed 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.

As a result of this strategic review, FirstEnergy announced in January 2017 that AE Supply and AGC entered into an asset purchase agreement to sell four of AE Supply’s natural gas generating plants and its approximately 59% of AGC’s interest in Bath County (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, 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. As a further condition to closing, FE will provide the purchaser two limited guarantees of certain obligations of AE Supply and AGC arising under the purchase agreement. 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 May 24, 2017, AE Supply and AGC and LS Power exercised a provision in the purchase agreement that allows either party to terminate the purchase agreement without penalty after June 23, 2017. All parties continue to negotiate, including consideration of various alternative structures regarding pricing and closing, and neither party has elected its termination rights under the provisions of the purchase agreement. As a result of the status of these ongoing negotiations regarding the asset purchase agreement and reflecting the impact of prevailing market conditions, CES recorded a non-cash pre-tax impairment charge of $131 million in the second quarter of 2017. FirstEnergy is targeting to close the transaction with revised terms in the second half of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents.

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 the recently announced directive by the Secretary of Energy to complete a study that explores critical issues central to protecting the long-term reliability of the electric grid, including the impact of federal policy interventions and the changing nature of electricity fuel mix, compensation of on-site fuel supply and other factors that strengthen grid resilience, and the impact of regulatory burdens, mandates and tax and subsidy policies on the premature retirement of baseload power plants;
- The resolution of legislation before the Ohio General Assembly that would create a zero-emission nuclear (ZEN) credit that would compensate nuclear power plants for their environmental attributes 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 approximately 60-65 million MWHs produced annually.

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

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 June 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 more than sufficient to fund capital expenditures and nuclear fuel purchases through March 2018. As previously disclosed, FES has $515 million of maturing debt in 2018, beginning in the second quarter. 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, even on a secured basis. 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 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.

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 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 statement 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. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard, which will be heavily dependent on the resolution of certain industry issues. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years.

2. EARNINGS 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 six months ended June 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 June 30		For the Six Months Ended June 30	
Reconciliation of Basic and Diluted Earnings (Loss) per Share of Common Stock	2017	2016	2017	2016
Net income (loss)	$174	$(1,089)	$379	$(761)
Weighted average number of basic shares outstanding	444	425	443	424
Assumed exercise of dilutive stock options and awards[1]	1	—	1	—
Weighted average number of diluted shares outstanding	445	425	444	424

Basic earnings (loss) per share of common stock	$0.39	$(2.56)	$0.86	$(1.79)
Diluted earnings (loss) per share of common stock	$0.39	$(2.56)	$0.85	$(1.79)

(1) For both the three and six months ended June 30, 2017, one million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. For both the three and six months ended June 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 June 30	2017	2016	2017	2016
	(In millions)			
Service costs	$52	$48	$1	$1
Interest costs	97	99	7	8
Expected return on plan assets	(112)	(100)	(7)	(8)
Amortization of prior service costs (credits)	2	2	(20)	(20)
Net periodic costs (credits)	$39	$49	$(19)	$(19)

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Six Months Ended June 30	2017	2016	2017	2016
	(In millions)			
Service costs	$104	$96	$2	$2
Interest costs	194	199	14	15
Expected return on plan assets	(224)	(197)	(15)	(16)
Amortization of prior service costs (credits)	4	4	(40)	(40)
Net periodic costs (credits)	$78	$102	$(39)	$(39)

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 June 30	$3	$ 6	$(4)	$(4)
For the Six Months Ended June 30	6	12	(8)	(8)

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 June 30	2017	2016	2017	2016
	(In millions)			
FirstEnergy	$27	$ 35	$(14)	$(15)
FES	3	6	(4)	(4)

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Six Months Ended June 30	2017	2016	2017	2016
	(In millions)			
FirstEnergy	$59	$ 72	$(29)	$(30)
FES	6	12	(8)	(8)

As of June 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 six months ended June 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 April 1, 2017	$(26)	$ 63	$ 138	$175
Other comprehensive income before reclassifications	—	4	—	4
Amounts reclassified from AOCI	1	(6)	(18)	(23)
Other comprehensive income (loss)	1	(2)	(18)	(19)
Income taxes (benefits) on other comprehensive income (loss)	1	—	(8)	(7)
Other comprehensive loss, net of tax	—	(2)	(10)	(12)
AOCI Balance as of June 30, 2017	$(26)	$ 61	$ 128	$163
AOCI Balance as of April 1, 2016	$(32)	$ 36	$ 175	$179
Other comprehensive income before reclassifications	—	47	—	47
Amounts reclassified from AOCI	2	(12)	(18)	(28)
Other comprehensive income (loss)	2	35	(18)	19
Income taxes (benefits) on other comprehensive income (loss)	1	13	(7)	7
Other comprehensive income (loss), net of tax	1	22	(11)	12
AOCI Balance as of June 30, 2016	$(31)	$ 58	$ 164	$191

	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	—	36	—	36
Amounts reclassified from AOCI	4	(22)	(36)	(54)
Other comprehensive income (loss)	4	14	(36)	(18)
Income taxes (benefits) on other comprehensive income (loss)	2	5	(14)	(7)
Other comprehensive income (loss), net of tax	2	9	(22)	(11)
AOCI Balance as of June 30, 2017	$(26)	$ 61	$ 128	$163

AOCI Balance as of January 1, 2016	$(33)	$ 18	$ 186	$171
Other comprehensive income before reclassifications	—	88	—	88
Amounts reclassified from AOCI	4	(25)	(36)	(57)
Other comprehensive income (loss)	4	63	(36)	31
Income taxes (benefits) on other comprehensive income (loss)	2	23	(14)	11
Other comprehensive income (loss), net of tax	2	40	(22)	20
AOCI Balance as of June 30, 2016	$(31)	$ 58	$ 164	$191

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

	For the Three Months Ended June 30		For the Six Months Ended June 30		Affected Line Item in Consolidated Statements of Income (Loss)
Reclassifications from AOCI[2]	2017	2016	2017	2016	
	(In millions)				
Gains & losses on cash flow hedges					
Long-term debt	$1	$2	$4	$4	Interest expense
	(1)	(1)	(2)	(2)	Income taxes (benefits)
	$—	$1	$2	$2	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(6)	$(12)	$(22)	$(25)	Investment income
	2	4	8	9	Income taxes (benefits)
	$(4)	$(8)	$(14)	$(16)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(18)	$(18)	$(36)	$(36)	[1]
	8	7	14	14	Income taxes (benefits)
	$(10)	$(11)	$(22)	$(22)	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 six months ended June 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 April 1, 2017	$(9)	$ 58	$ 28	$77
Other comprehensive income before reclassifications	—	12	—	12
Amounts reclassified from AOCI	—	(6)	(4)	(10)
Other comprehensive income (loss)	—	6	(4)	2
Income taxes (benefits) on other comprehensive income (loss)	—	2	(2)	—
Other comprehensive income (loss), net of tax	—	4	(2)	2
AOCI Balance as of June 30, 2017	$(9)	$ 62	$ 26	$79
AOCI Balance as of April 1, 2016	$(9)	$ 30	$ 37	$58
Other comprehensive income before reclassifications	—	44	—	44
Amounts reclassified from AOCI	(1)	(11)	(3)	(15)
Other comprehensive income (loss)	(1)	33	(3)	29
Income taxes (benefits) on other comprehensive income (loss)	—	13	(1)	12
Other comprehensive income (loss), net of tax	(1)	20	(2)	17
AOCI Balance as of June 30, 2016	$(10)	$ 50	$ 35	$75

	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	—	43	—	43
Amounts reclassified from AOCI	—	(21)	(7)	(28)
Other comprehensive income (loss)	—	22	(7)	15
Income taxes (benefits) on other comprehensive income (loss)	—	8	(3)	5
Other comprehensive income (loss), net of tax	—	14	(4)	10
AOCI Balance as of June 30, 2017	$(9)	$ 62	$ 26	$79

AOCI Balance as of January 1, 2016	$(9)	$ 16	$ 39	$46
Other comprehensive income before reclassifications	—	80	—	80
Amounts reclassified from AOCI	(1)	(24)	(7)	(32)
Other comprehensive income (loss)	(1)	56	(7)	48
Income taxes (benefits) on other comprehensive income (loss)	—	22	(3)	19
Other comprehensive income (loss), net of tax	(1)	34	(4)	29
AOCI Balance as of June 30, 2016	$(10)	$ 50	$ 35	$75

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

Reclassifications from AOCI[2]	For the Three Months Ended June 30		For the Six Months Ended June 30		Affected Line Item in Consolidated Statements of Income (Loss)
	2017	2016	2017	2016	
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$—	$(1)	$—	$(1)	Other operating expenses
	—	—	—	—	Income taxes (benefits)
	$—	$(1)	$—	$(1)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(6)	$(11)	$(21)	$(24)	Investment income
	2	4	8	9	Income taxes (benefits)
	$(4)	$(7)	$(13)	$(15)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(4)	$(3)	$(7)	$(7)	[1]
	2	1	3	3	Income taxes (benefits)
	$(2)	$(2)	$(4)	$(4)	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 June 30, 2017 and 2016 was 40.2% on pre-tax income and 10.7% on pre-tax losses, respectively. FirstEnergy's effective tax rate for the six months ended June 30, 2017 and 2016 was 39.1% on pre-tax income and (12.2)% on pre-tax losses, respectively. The change in the effective tax rate for both periods is primarily due to the impairment of $800 million of goodwill 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 impact the 2016 effective tax rate.

FES’ effective tax rate for the three months ended June 30, 2017 and 2016 was 54.8% on pre-tax income and 24.6% on pre-tax losses, respectively. FES' effective tax rate for the six months ended June 30, 2017 and 2016 was 22.8% and 16.6%, respectively. The change in the effective tax rate for both periods was primarily due to the re-measurement of ADIT resulting from the transfer of nuclear decommissioning trust assets and asset retirement obligations from OE and TE to NG, as discussed in Note 9, "Asset Retirement Obligation," as well as a $65 million valuation allowance recognized in the second quarter of 2016 against state and local NOL carryforwards and the impairment of goodwill in 2016, of which $23 million was non-deductible for tax purposes.

As of June 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 February 2017, the IRS completed its examination of FirstEnergy's 2015 federal income tax return and issued a Full Acceptance Letter with no changes or adjustments to FirstEnergy's taxable income or effective tax rate.

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 June 30, 2017 and December 31, 2016, $327 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 June 30, 2017 and December 31, 2016, $63 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 June 30, 2017 and December 31, 2016, $395 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 June 30, 2017 and 2016 were $25 million and $25 million, respectively, and $53 million and $56 million during the six months ended June 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 June 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 each company's net exposure to loss based upon the casualty value provisions as of June 30, 2017:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
	(In millions)		
FirstEnergy and FES	$1,081	$ 859	$ 222

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 ARO's to NG associated with Beaver Valley Unit 2. See Note 9, "Asset Retirement Obligations," for additional information.

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 three 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 June 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 six months ended June 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	June 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	$—	$1,216	$—	$1,216	$—	$1,247	$—	$1,247
Derivative assets - commodity contracts	—	50	—	50	10	200	—	210
Derivative assets - FTRs	—	—	4	4	—	—	7	7
Derivative assets - NUG contracts[1]	—	—	—	—	—	—	1	1
Equity securities[2]	1,002	—	—	1,002	925	—	—	925
Foreign government debt securities	—	95	—	95	—	78	—	78
U.S. government debt securities	—	156	—	156	—	161	—	161
U.S. state debt securities	—	258	—	258	—	246	—	246
Other[3]	114	150	—	264	199	123	—	322
Total assets	$1,116	$1,925	$4	$3,045	$1,134	$2,055	$8	$3,197
Liabilities								
Derivative liabilities - commodity contracts	$—	$(18)	$—	$(18)	$(6)	$(118)	$—	$(124)
Derivative liabilities - FTRs	—	—	(2)	(2)	—	—	(6)	(6)
Derivative liabilities - NUG contracts[1]	—	—	(99)	(99)	—	—	(108)	(108)
Total liabilities	$—	$(18)	$(101)	$(119)	$(6)	$(118)	$(114)	$(238)
Net assets (liabilities)[4]	$1,116	$1,907	$(97)	$2,926	$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 $(18) million and $(3) million as of June 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 June 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	—	(10)	(10)	—	(2)	(2)
Purchases	—	—	—	4	(1)	3
Settlements	(1)	19	18	(7)	7	—
June 30, 2017 Balance	$—	$ (99)	$(99)	$4	$ (2)	$2

[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 June 30, 2017:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 2	Model	RTO auction clearing prices	$(2.00) to $4.10	$0.60	Dollars/MWH
NUG Contracts	$ (99)	Model	Generation	400 to 2,545,000	515,000	MWH
			Regional electricity prices	$31.20 to $33.60	$31.30	Dollars/MWH

FES

Recurring Fair Value Measurements	June 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	$—	$761	$—	$761	$—	$726	$—	$726
Derivative assets - commodity contracts	—	49	—	49	10	200	—	210
Derivative assets - FTRs	—	—	1	1	—	—	4	4
Equity securities[1]	720	—	—	720	634	—	—	634
Foreign government debt securities	—	66	—	66	—	58	—	58
U.S. government debt securities	—	137	—	137	—	48	—	48
U.S. state debt securities	—	4	—	4	—	3	—	3
Other[2]	2	108	—	110	2	81	—	83
Total assets	$722	$1,125	$1	$1,848	$646	$1,116	$4	$1,766
Liabilities								
Derivative liabilities - commodity contracts	$—	$(17)	$—	$(17)	$(6)	$(118)	$—	$(124)
Derivative liabilities - FTRs	—	—	(2)	(2)	—	—	(5)	(5)
Total liabilities	$—	$(17)	$(2)	$(19)	$(6)	$(118)	$(5)	$(129)
Net assets (liabilities)[3]	$722	$1,108	$(1)	$1,829	$640	$998	$(1)	$1,637

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

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

(3) Excludes $(3) million and $2 million as of June 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 June 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)	5	1
June 30, 2017 Balance	$1	$ (2)	$ (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 June 30, 2017:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (1)	Model	RTO auction clearing prices	($2.00) to $4.10	$0.20	Dollars/MWH

INVESTMENTS

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

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

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

During the second quarter of 2017, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in the Beaver Valley Unit 2 and the expiration of the leases, OE and TE transferred NDT assets of $189 million associated with their leasehold interests to NG. See Note 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 June 30, 2017 and December 31, 2016:

	June 30, 2017[1]			December 31, 2016[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,708	$ 44	$1,752	$1,735	$ 38	$1,773
FES	961	32	993	847	27	874
Equity securities						
FirstEnergy	$876	$ 126	$1,002	$822	$ 103	$925
FES	629	91	720	564	70	634

(1) Excludes short-term cash investments: FirstEnergy - $87 million; FES - $80 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 six months ended June 30, 2017 and 2016 were as follows:

For the Three Months Ended

June 30, 2017	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$519	$ 98	$ (91)	$(4)	$ 25
FES	206	69	(62)	(4)	15

June 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$559	$ 34	$ (24)	$(2)	$ 25
FES	303	25	(15)	(2)	13

For the Six Months Ended

June 30, 2017	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,257	$ 183	$ (154)	$(7)	$ 48
FES	437	133	(110)	(7)	29

June 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,024	$ 95	$ (73)	$(10)	$ 48
FES	441	67	(43)	(9)	26

Held-To-Maturity Securities

Unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of June 30, 2017 and December 31, 2016 are immaterial to FirstEnergy. Investments in employee benefit trusts and equity method investments totaling $254 million as of June 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:

	June 30, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$22,646	$23,164	$19,885	$19,829
FES	2,837	1,518	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 June 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 $12 million as of June 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 $29 million (FES $3 million) and $33 million (FES $3 million) as of June 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 six months ended June 30, 2017 and 2016.

As of June 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 June 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 $6 million and $10 million as of June 30, 2017 and December 31, 2016, respectively. During the next twelve months, approximately $3 million of unamortized gains are expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $2 million during the three months ended June 30, 2017 and $3 million during the three months ended June 30, 2016. Amortization of unamortized gains included in long-term debt totaled approximately $4 million during the six months ended June 30, 2017 and $6 million during the six months ended June 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 June 30, 2017, FirstEnergy’s net asset position under commodity derivative contracts was $32 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 June 30, 2017, an increase in commodity prices of 10% would decrease net income by approximately $15 million during the next twelve months.

NUGs

As of June 30, 2017, FirstEnergy's net liability position under NUG contracts was $99 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 June 30, 2017, FirstEnergy's net asset position associated with FTRs was $2 million and FES' net liability was $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		Derivative Liabilities	Fair Value	
	June 30, 2017	December 31, 2016		June 30, 2017	December 31, 2016
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$41	$ 133	Commodity Contracts	$(16)	$ (72)
FTRs	4	7	FTRs	(2)	(6)
	45	140		(18)	(78)
			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs[1]	(99)	(108)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Other		
Commodity Contracts	9	77	Commodity Contracts	(2)	(52)
NUGs[1]	—	1			
	9	78		(101)	(160)
Derivative Assets	$54	$ 218	Derivative Liabilities	$(119)	$ (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		Derivative Liabilities	Fair Value	
	June 30, 2017	December 31, 2016		June 30, 2017	December 31, 2016
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$40	$ 133	Commodity Contracts	$(16)	$ (72)
FTRs	1	4	FTRs	(2)	(5)
	41	137		(18)	(77)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Other		
Commodity Contracts	9	77	Commodity Contracts	(1)	(52)
	9	77		(1)	(52)
Derivative Assets	$50	$ 214	Derivative Liabilities	$(19)	$ (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:

June 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	$50	$ (15)	$ —	$35
FTRs	4	(2)	—	2
	$54	$ (17)	$ —	$37
Derivative Liabilities				
Commodity contracts	$(18)	$ 15	$ —	$(3)
FTRs	(2)	2	—	—
NUG contracts	(99)	—	—	(99)
	$(119)	$ 17	$ —	$(102)

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	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:

June 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	$49	$ (15)	$ —	$ 34
FTRs	1	(1)	—	—
	$50	$ (16)	$ —	$ 34
Derivative Liabilities				
Commodity contracts	$(17)	$ 15	$ —	$ (2)
FTRs	(2)	1	—	(1)
	$(19)	$ 16	$ —	$ (3)

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	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 June 30, 2017:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	2	11	(9)	MWH
FTRs	19	—	19	MWH
NUGs	3	—	3	MWH

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

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	2	11	(9)	MWH
FTRs	10	—	10	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 six months ended June 30, 2017 and 2016, are summarized in the following tables:

	For the Three Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2017			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(8)	$ 2	$(6)
Realized Gain (Loss) Reclassified to:			
Revenues	$15	$ 1	$16
Purchased Power Expense	(4)	—	(4)
Other Operating Expense	—	(4)	(4)
Fuel Expense	1	—	1

	For the Three Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(79)	$ 9	$(70)
Realized Gain (Loss) Reclassified to:			
Revenues	$59	$ 1	$60
Purchased Power Expense	(37)	—	(37)
Other Operating Expense	—	(9)	(9)

	For the Six Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2017			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(54)	$1	$(53)
Realized Gain (Loss) Reclassified to:			
Revenues	$40	$1	$41
Purchased Power Expense	(11)	—	(11)
Other Operating Expense	—	(13)	(13)
Fuel Expense	5	—	5

	For the Six Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(17)	$12	$(5)
Realized Gain (Loss) Reclassified to:			
Revenues	$130	$3	$133
Purchased Power Expense	(83)	—	(83)
Other Operating Expense	—	(22)	(22)
Fuel Expense	(7)	—	(7)

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

	For the Three Months Ended June 30		
	Commodity Contracts	FTRs	Total
2017	(In millions)		
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(8)	$ 2	$(6)
Realized Gain (Loss) Reclassified to:			
Revenues	$15	$ 1	$16
Purchased Power Expense	(4)	—	(4)
Other Operating Expense	—	(4)	(4)

	For the Three Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(79)	$ 9	$(70)
Realized Gain (Loss) Reclassified to:			
Revenues	$59	$ 1	$60
Purchased Power Expense	(37)	—	(37)
Other Operating Expense	—	(9)	(9)

	For the Six Months Ended June 30		
	Commodity Contracts	FTRs	Total
2017	(In millions)		
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(54)	$1	$(53)
Realized Gain (Loss) Reclassified to:			
Revenues	$40	$1	$41
Purchased Power Expense	(11)	—	(11)
Other Operating Expense	—	(13)	(13)

	For the Six Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$(17)	$12	$(5)
Realized Gain (Loss) Reclassified to:			
Revenues	$130	$3	$133
Purchased Power Expense	(83)	—	(83)
Other Operating Expense	—	(22)	(22)

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 six months ended June 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 June 30		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net liability as of April 1, 2017	$(103)	$ (2)	$(105)
Unrealized loss	(5)	—	(5)
Purchases	—	3	3
Settlements	10	2	12
Outstanding net asset (liability) as of June 30, 2017	$(98)	$ 3	$(95)
Outstanding net liability as of April 1, 2016	$(135)	$ (2)	$(137)
Purchases	—	4	4
Settlements	11	2	13
Outstanding net asset (liability) as of June 30, 2016	$(124)	$ 4	$(120)

	For the Six Months Ended June 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	(10)	(1)	(11)
Purchases	—	3	3
Settlements	19	(1)	18
Outstanding net asset (liability) as of June 30, 2017	$(98)	$ 3	$(95)
Outstanding net asset (liability) as of January 1, 2016	$(136)	$ 1	$(135)
Unrealized loss	(12)	—	(12)
Purchases	—	4	4
Settlements	24	(1)	23
Outstanding net asset (liability) as of June 30, 2016	$(124)	$ 4	$(120)

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.

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 $787 million and $713 million, as of June 30, 2017 and December 31, 2016, respectively. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

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. As of June 30, 2017, NG owns 100% of Beaver Valley Unit 2.

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 $52 million was incurred through June 30, 2017. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE.

On February 27, 2013, the MDPSC issued an order requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 2013 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 2013 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting, as well as the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the Maryland utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The

MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

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

NEW JERSEY

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

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 this generic CTA proceeding to the New Jersey Superior Court and JCP&L filed to participate as a respondent in that proceeding supporting the order. Briefing was completed, and the oral argument was held on October 25, 2016.

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 December 7, 2016, the PUCO granted the applications for rehearing for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO. For additional information, see "FERC Matters - Ohio ESP IV PPA" below.

Under ORC 4928.66, the Ohio Companies 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 SB 310 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. There is an additional application for rehearing that remains pending before the PUCO.

PENNSYLVANIA

The Pennsylvania Companies previously operated under DSPs that expired on May 31, 2017, and provided for the competitive procurement of generation supply for customers that did not choose an alternative EGS or for customers of alternative EGSs that failed to provide the contracted service.

The Pennsylvania Companies currently 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 current 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.

ME, PN, Penn and WP currently 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 October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.3 million; PN $56.7 million; Penn $56.4 million; and ME $43.4 million, which were approved by the PPUC on February 11, 2016. On March 1, 2017, ME, PN and Penn filed petitions with the PPUC to modify their LTIIPs for the four remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. ME proposed to increase its LTIIP spending by $8.2

million per year, PN by $3.3 million per year, and Penn by $2.5 million per year. The petitions were approved by the PPUC in an Order entered June 14, 2017.

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 and briefing has been completed.

WEST VIRGINIA

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

On September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year.

On December 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 applications with the WVPSC and MP and AE Supply filed with FERC requesting authorization for such purchase. The WVPSC has scheduled a hearing on this matter for September 26-28, 2017, and public hearings for 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. With respect to the Bath County RFP, MP does not plan to move forward with the sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

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. 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, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which FERC denied on May 19, 2016. 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. On a related issue, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

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

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

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. The settlement process is ongoing.

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.

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 subsequently 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. The requests for rehearing and the compliance filing remain pending before FERC.

Market-Based Rate Authority, Triennial Update

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

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 June 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 ($466 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 June 30, 2017, FES has posted collateral of $123 million and AE Supply has posted no collateral. The Regulated Distribution Segment has posted collateral of $4 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of June 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	—	—	43	—	43
Surety Bonds (Collateralized Amount)[1]	65	25	92	187	369
Total Exposure from Contractual Obligations	$71	$ 27	$ 135	$187	$420

[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 is a guarantor for $169 million of FES' surety bonds for the benefit of the PA DEP with respect to LBR and a guarantor for a $12 million FES surety bond for the benefit of the Ohio Environmental Protection Agency relating to the W.H. Sammis generating station.

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of June 30, 2017, FES has $2 million collateral posted with their 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 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. Depending on the outcome of the appeals and on how the EPA and the states implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's and FES' operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but the EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State 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 July 20, 2017, the State of Maryland notified the EPA of its intent to sue the EPA for failing to act on Maryland’s CAA Section 126 petition following the 60 day notification period required by the CAA. 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 arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, all plants covered by this contract were deactivated by April 16, 2015. 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, agree 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, 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 does 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. FirstEnergy, FES 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. FirstEnergy and FES dispute the allegations and intend to vigorously defend the merits of the lawsuit. At this time, FirstEnergy and FES 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 United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. The EPA released its final regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA’s state specific CO_2 emission rate goals. The EPA’s CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2016, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. 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. 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. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

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

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

Regulation of Waste Disposal

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

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, any changes in timing and closure plan requirements in the future, including changes resulting from the strategic review at CES, could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The CCRs from the Bruce Mansfield plant are being beneficially reused with the majority used for reclamation of a site owned by the Marshall County Coal Company in Moundsville, W. Va. and the remainder recycled into drywall by National Gypsum. These beneficial reuse options should be sufficient for ongoing plant operations, however, the Bruce Mansfield plant is pursuing other options. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notices of Appeal with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of June 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 June 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 June 30, 2017, FirstEnergy had approximately $2.6 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs 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 upgrades at FirstEnergy’s nuclear facilities have been implemented, the improvements still remain subject to regulatory approval.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units, have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. 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 six months ended June 30, 2017 and 2016, Condensed Consolidating Balance Sheets as of June 30, 2017 and December 31, 2016, and Condensed Consolidating Statements of Cash Flows for the six months ended June 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 (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Three Months Ended June 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$717	$474	$360	$ (810)	$ 741
OPERATING EXPENSES:					
Fuel	—	106	48	—	154
Purchased power from affiliates	811	—	38	(810)	39
Purchased power from non-affiliates	156	—	—	—	156
Other operating expenses	63	58	153	12	286
Provision for depreciation	3	9	16	(1)	27
General taxes	5	5	8	—	18
Total operating expenses	1,038	178	263	(799)	680
OPERATING INCOME (LOSS)	(321)	296	97	(11)	61
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	247	10	21	(263)	15
Interest expense — affiliates	(20)	(3)	(1)	19	(5)
Interest expense — other	(12)	(26)	(11)	14	(35)
Capitalized interest	—	—	6	—	6
Total other income (expense)	215	(19)	15	(230)	(19)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(106)	277	112	(241)	42
INCOME TAXES (BENEFITS)	(125)	102	45	1	23
NET INCOME (LOSS)	$19	$175	$67	$ (242)	$ 19
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$19	$175	$67	$ (242)	$ 19
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(4)	(4)	—	4	(4)
Change in unrealized gains on available-for-sale securities	6	—	6	(6)	6
Other comprehensive income (loss)	2	(4)	6	(2)	2
Income taxes (benefits) on other comprehensive income (loss)	—	(2)	2	—	—
Other comprehensive income (loss), net of tax	2	(2)	4	(2)	2
COMPREHENSIVE INCOME (LOSS)	$21	$173	$71	$ (244)	$ 21

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

For the Six Months Ended June 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$1,597	$710	$696	$ (1,348)	$ 1,655
OPERATING EXPENSES:					
Fuel	—	204	94	—	298
Purchased power from affiliates	1,474	—	76	(1,348)	202
Purchased power from non-affiliates	316	—	—	—	316
Other operating expenses	177	283	320	24	804
Provision for depreciation	6	16	31	(1)	52
General taxes	11	13	15	—	39
Total operating expenses	1,984	516	536	(1,325)	1,711
OPERATING INCOME (LOSS)	(387)	194	160	(23)	(56)
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income (loss) from equity investees	229	20	48	(262)	35
Miscellaneous income	—	—	5	—	5
Interest expense — affiliates	(38)	(6)	(2)	39	(7)
Interest expense — other	(23)	(53)	(22)	28	(70)
Capitalized interest	—	1	13	—	14
Total other income (expense)	168	(38)	42	(195)	(23)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(219)	156	202	(218)	(79)
INCOME TAXES (BENEFITS)	(158)	60	78	2	(18)
NET INCOME (LOSS)	$(61)	$96	$124	$ (220)	$ (61)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(61)	$96	$124	$ (220)	$ (61)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(7)	(7)	—	7	(7)
Change in unrealized gains on available-for-sale securities	22	—	22	(22)	22
Other comprehensive income (loss)	15	(7)	22	(15)	15
Income taxes (benefits) on other comprehensive income (loss)	5	(3)	8	(5)	5
Other comprehensive income (loss), net of tax	10	(4)	14	(10)	10
COMPREHENSIVE INCOME (LOSS)	$(51)	$92	$138	$ (230)	$ (51)

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

For the Three Months Ended June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$1,061	$400	$473	$ (832)	$ 1,102
OPERATING EXPENSES:					
Fuel	—	181	47	—	228
Purchased power from affiliates	950	—	49	(832)	167
Purchased power from non-affiliates	266	—	—	—	266
Other operating expenses	119	88	148	14	369
Provision for depreciation	3	32	50	(1)	84
General taxes	7	6	6	—	19
Impairment of assets	23	517	—	—	540
Total operating expenses	1,368	824	300	(819)	1,673
OPERATING INCOME (LOSS)	(307)	(424)	173	(13)	(571)
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	(163)	7	22	153	19
Miscellaneous income	1	—	—	—	1
Interest expense — affiliates	(12)	(2)	—	13	(1)
Interest expense — other	(13)	(26)	(13)	15	(37)
Capitalized interest	—	2	6	—	8
Total other income (expense)	(187)	(19)	15	181	(10)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(494)	(443)	188	168	(581)
INCOME TAXES (BENEFITS)	(56)	(149)	61	1	(143)
NET INCOME (LOSS)	$(438)	$(294)	$127	$ 167	$ (438)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(438)	$(294)	$127	$ 167	$ (438)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(3)	(4)	—	4	(3)
Amortized gains on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gains on available for sale securities	33	—	32	(32)	33
Other comprehensive income (loss)	29	(4)	32	(28)	29
Income taxes (benefits) on other comprehensive income (loss)	12	(2)	13	(11)	12
Other comprehensive income (loss), net of tax	17	(2)	19	(17)	17

COMPREHENSIVE INCOME (LOSS)	$(421)	$(296)	$146	$ 150	$ (421)

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

For the Six Months Ended June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$2,216	$815	$1,004	$ (1,734)	$ 2,301
OPERATING EXPENSES:					
Fuel	—	300	93	—	393
Purchased power from affiliates	1,877	—	106	(1,734)	249
Purchased power from non-affiliates	643	—	—	—	643
Other operating expenses	123	159	301	26	609
Provision for depreciation	6	63	100	(2)	167
General taxes	15	16	14	—	45
Impairment of assets	23	517	—	—	540
Total operating expenses	2,687	1,055	614	(1,710)	2,646
OPERATING INCOME (LOSS)	(471)	(240)	390	(24)	(345)
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	86	13	39	(106)	32
Miscellaneous income	3	—	—	—	3
Interest expense — affiliates	(21)	(4)	(2)	24	(3)
Interest expense — other	(26)	(52)	(24)	29	(73)
Capitalized interest	—	4	14	—	18
Total other income (expense)	42	(39)	27	(53)	(23)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(429)	(279)	417	(77)	(368)
INCOME TAXES (BENEFITS)	(122)	(88)	147	2	(61)
NET INCOME (LOSS)	$(307)	$(191)	$270	$ (79)	$ (307)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(307)	$(191)	$270	$ (79)	$ (307)
OTHER COMPREHENSIVE INCOME (LOSS)					
Pension and OPEB prior service costs	(7)	(7)	—	7	(7)
Amortized gains on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gains on available-for-sale securities	56	—	55	(55)	56
Other comprehensive income (loss)	48	(7)	55	(48)	48
Income taxes (benefits) on other comprehensive income (loss)	19	(3)	21	(18)	19
Other comprehensive income (loss), net of tax	29	(4)	34	(30)	29
COMPREHENSIVE INCOME (LOSS)	$(278)	$(195)	$304	$ (109)	$ (278)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of June 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$ —	$ 2
Receivables-					
Customers	185	—	—	—	185
Affiliated companies	300	240	237	(392)	385
Other	10	2	—	—	12
Notes receivable from affiliated companies	361	1,599	1,366	(3,326)	—
Materials and supplies	41	137	82	—	260
Derivatives	41	—	—	—	41
Collateral	98	13	—	—	111
Prepayments and other	40	11	—	—	51
	1,076	2,004	1,685	(3,718)	1,047
PROPERTY, PLANT AND EQUIPMENT:					
In service	121	2,561	4,981	(281)	7,382
Less — Accumulated provision for depreciation	59	1,936	4,248	(188)	6,055
	62	625	733	(93)	1,327
Construction work in progress	2	55	242	—	299
	64	680	975	(93)	1,626
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,793	—	1,793
Investment in affiliated companies	3,230	—	—	(3,230)	—
Other	—	9	—	—	9
	3,230	9	1,793	(3,230)	1,802
DEFERRED CHARGES AND OTHER ASSETS:					
Property taxes	—	6	14	—	20
Accumulated deferred income tax benefits	440	1,203	738	(273)	2,108
Derivatives	9	—	—	—	9
Other	32	329	—	18	379
	481	1,538	752	(255)	2,516
	$4,851	$4,231	$5,205	$ (7,296)	$ 6,991
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$183	$99	$ (27)	$ 255
Short-term borrowings - affiliated companies	3,241	360	—	(3,326)	275
Accounts payable-					
Affiliated companies	477	92	168	(473)	264
Other	17	74	—	—	91
Accrued taxes	48	51	59	(29)	129
Derivatives	15	3	—	—	18
Other	47	80	10	33	170
	3,845	843	336	(3,822)	1,202

CAPITALIZATION:					
Total equity	239	914	2,217	(3,131)	239
Long-term debt and other long-term obligations	691	1,938	1,022	(1,078)	2,573
	930	2,852	3,239	(4,209)	2,812
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	740	740
Accumulated deferred income taxes	5	—	—	(5)	—
Retirement benefits	27	178	—	—	205
Asset retirement obligations	—	188	787	—	975
Derivatives	1	—	—	—	1
Other	43	170	843	—	1,056
	76	536	1,630	735	2,977
	$4,851	$4,231	$5,205	$ (7,296)	$ 6,991

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
Prepayments 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
Derivatives	52	—	—	—	52
Other	42	85	860	—	987
	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 Six Months Ended June 30, 2017	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(411)	$340	$379	$ (13)	$ 295
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	272	—	—	(98)	174
Redemptions and Repayments-					
Long-term debt	—	(171)	(5)	13	(163)
Short-term borrowings, net	—	(122)	—	122	—
Other	(1)	(3)	—	—	(4)
Net cash provided from (used for) financing activities	271	(296)	(5)	37	7
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	—	(30)	(139)	—	(169)
Nuclear fuel	—	—	(134)	—	(134)
Sales of investment securities held in trusts	—	—	437	—	437
Purchases of investment securities held in trusts	—	—	(466)	—	(466)
Loans to affiliated companies, net	140	(14)	(73)	(24)	29
Other	—	—	1	—	1
Net cash provided from (used for) investing activities	140	(44)	(374)	(24)	(302)
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

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(335)	$308	$596	$ (12)	$ 557
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	322	89	8	(209)	210
Redemptions and Repayments-					
Long-term debt	—	(12)	(245)	12	(245)
Other	(1)	(2)	—	—	(3)
Net cash provided from (used for) financing activities	321	75	(237)	(197)	(38)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(27)	(126)	(182)	—	(335)
Nuclear fuel	—	—	(188)	—	(188)
Sales of investment securities held in trusts	—	—	441	—	441
Purchases of investment securities held in trusts	—	—	(467)	—	(467)
Cash Investments	11	—	—	—	11
Loans to affiliated companies, net	22	(257)	37	209	11
Other	8	—	—	—	8
Net cash provided from (used for) investing activities	14	(383)	(359)	209	(519)
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 further FERC hearing and settlement procedures. 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 June 30, 2017, this business segment controlled 13,162 MWs of electric generating capacity, including, as discussed in Note 14, "Asset Impairments," 1,572 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 June 30, 2017, Corporate/Other had $7.45 billion of stand-alone holding company long-term debt, of which 19% was subject to variable-interest rates, and $150 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)					
June 30, 2017						
External revenues	$2,262	$ 327	$ 778	$ —	$ (58)	$ 3,309
Internal revenues	—	—	86	—	(86)	—
Total revenues	2,262	327	864	—	(144)	3,309
Depreciation	179	54	29	19	—	281
Amortization of regulatory assets, net	62	3	—	—	—	65
Impairment of assets (Note 14)	—	—	131	—	—	131
Investment income	14	—	12	2	(11)	17
Interest expense	134	39	47	70	—	290
Income taxes (benefits)	121	53	(30)	(27)	—	117
Net income (loss)	205	92	(56)	(67)	—	174
Total assets	27,660	9,142	5,887	638	—	43,327
Total goodwill	5,004	614	—	—	—	5,618
Property additions	304	245	96	21	—	666
June 30, 2016						
External revenues	$2,189	$ 275	$ 1,008	$ —	$ (71)	$ 3,401
Internal revenues	—	—	108	—	(108)	—
Total revenues	2,189	275	1,116	—	(179)	3,401
Depreciation	168	46	103	17	—	334
Amortization of regulatory assets, net	61	2	—	—	—	63
Impairment of assets (Note 14)	—	—	1,447	—	—	1,447
Investment income	13	—	18	—	(12)	19
Interest expense	148	39	48	54	—	289
Income taxes (benefits)	80	46	(230)	(26)	—	(130)
Net income (loss)	139	78	(1,259)	(47)	—	(1,089)
Total assets	27,448	8,314	15,464	175	—	51,401
Total goodwill	5,004	614	—	—	—	5,618
Property additions	287	277	213	17	—	794
For the Six Months Ended						
June 30, 2017						
External revenues	$4,752	$ 640	$ 1,592	$ —	$ (123)	$ 6,861
Internal revenues	—	—	203	—	(203)	—
Total revenues	4,752	640	1,795	—	(326)	6,861
Depreciation	357	105	57	37	—	556
Amortization of regulatory assets, net	119	5	—	—	—	124
Impairment of assets (Note 14)	—	—	131	—	—	131
Investment income	28	—	32	5	(24)	41
Interest expense	272	78	92	135	—	577
Income taxes (benefits)	259	105	(65)	(56)	—	243

Net income (loss)	442	180	(123)	(120)	—	379
Property additions	568	469	188	29	—	1,254
June 30, 2016						
External revenues	$4,699	$ 561	$ 2,160	$ —	$ (150)	$ 7,270
Internal revenues	—	—	260	—	(260)	—
Total revenues	4,699	561	2,420	—	(410)	7,270
Depreciation	335	91	205	32	—	663
Amortization of regulatory assets, net	120	4	—	—	—	124
Impairment of assets (Note 14)	—	—	1,447	—	—	1,447
Investment income	24	—	33	11	(21)	47
Interest expense	298	79	95	105	—	577
Income taxes (benefits)	174	93	(145)	(39)	—	83
Net income (loss)	297	159	(1,115)	(102)	—	(761)
Property additions	528	556	382	26	—	1,492

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14. ASSET IMPAIRMENTS

Competitive Generation Asset Sale

As disclosed in Note 1, "Organization and Basis of Presentation," FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement to sell four of AE Supply’s natural gas generating plants and approximately 59% of AGC’s interest in 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, third party consents, and the satisfaction and discharge of $305 million of AE Supply senior notes, which would require the payment of a “make-whole” premium estimated to be approximately $100 million based on current interest rates. Additionally, as a further condition to closing, FE will provide the purchaser two limited guarantees of certain obligations of AE Supply and AGC arising under the purchase agreement. On February 17, 2017, AE Supply and AGC submitted a filing with FERC and on June 13, 2017, FERC issued an order authorizing the transaction as requested. The parties will also file a request for authorization to transfer the hydroelectric license 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 May 24, 2017, AE Supply and AGC and LS Power exercised a provision in the purchase agreement that allows either party to terminate the purchase agreement without penalty after June 23, 2017. All parties continue to negotiate, including consideration of various alternative structures regarding pricing and closing, and neither party has elected its termination rights under the provisions of the purchase agreement. As a result of the status of these ongoing negotiations regarding the asset purchase agreement and reflecting the impact of prevailing market conditions, CES recorded a non-cash pre-tax impairment charge of $131 million in the second quarter of 2017. FirstEnergy is targeting to close the transaction with revised terms in the second half of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents. There can be no assurance that any such approvals will be obtained and/or any such conditions will be satisfied or that such sale will be consummated.

Assets held for sale as of June 30, 2017 include property, plant and equipment (net of accumulated provision for depreciation) of $792 million, investments of $20 million, materials and supplies inventory of $4 million, and AROs of approximately $1 million.

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 the caption of Fuel 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 within the caption Impairment of assets 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 further FERC hearing and settlement procedures. 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 June 30, 2017, this business segment controlled 13,162 MWs of electric generating capacity, including, as further discussed below, 1,572 MWs of natural gas and hydroelectric generating capacity subject to an asset purchase agreement with 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 June 30, 2017, Corporate/Other had $7.45 billion of stand-alone holding company long-term debt, of which 19% was subject to variable-interest rates, and $150 million was borrowed by FE under its revolving credit facility.

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EXECUTIVE SUMMARY

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

Over the past several years, CES has been impacted by a prolonged decrease in demand and excess generation supply in the PJM Region, which has resulted in a period of protracted low power and capacity prices. To address this, CES sold or deactivated more than 6,770 MWs of competitive generation from 2012 to 2015 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 continue to be weak, as evidenced by the significantly depressed 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.

As a result of this strategic review, FirstEnergy announced in January 2017 that AE Supply and AGC entered into an asset purchase agreement to sell four of AE Supply’s natural gas generating plants and its approximately 59% of AGC’s interest in Bath County (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, 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. As a further condition to closing, FE will provide the purchaser two limited guarantees of certain obligations of AE Supply and AGC arising under the purchase agreement. 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 May 24, 2017, AE Supply and AGC and LS Power exercised a provision in the purchase agreement that allows either party to terminate the purchase agreement without penalty after June 23, 2017. All parties continue to negotiate, including consideration of various alternative structures regarding pricing and closing, and neither party has elected its termination rights under the provisions of the purchase agreement. As a result of the status of these ongoing negotiations regarding the asset purchase agreement and reflecting the impact of prevailing market conditions, CES recorded a non-cash pre-tax impairment charge of $131 million in the second quarter of 2017. FirstEnergy is targeting to close the transaction with revised terms in the second half of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents.

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 the recently announced directive by the Secretary of Energy to complete a study that explores critical issues central to protecting the long-term reliability of the electric grid, including the impact of federal policy interventions and the changing nature of electricity fuel mix, compensation of on-site fuel supply and other factors that strengthen grid resilience, and the impact of regulatory burdens, mandates and tax and subsidy policies on the premature retirement of baseload power plants;
- The resolution of legislation before the Ohio General Assembly that would create a zero-emission nuclear (ZEN) credit that would compensate nuclear power plants for their environmental attributes 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 approximately 60-65 million MWHs produced annually.

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

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of June 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 more than sufficient to fund capital expenditures and nuclear fuel purchases through March 2018. As previously disclosed, FES has $515 million of maturing debt in 2018, beginning in the second quarter. 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, even on a secured basis. 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 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. These regulated businesses are expected to provide 4%–6% compounded annual earnings growth from 2016 to 2019, which increases to 7%–9% with the inclusion of the DMR in Ohio that was implemented on January 1, 2017 to support investment in modernization of the Ohio Companies' distribution systems.

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 FERC hearing and settlement procedures. FirstEnergy believes its existing transmission infrastructure creates incremental investment opportunities of approximately $20 billion beyond those identified through 2021 which will make the transmission system more reliable, robust, secure and resistant to extreme weather events, with improved operational flexibility. FirstEnergy plans to fund a portion of these investments with $500 million of equity annually from 2017 through 2019.

In addition to the significant opportunities at Regulated Transmission, the scale and diversity of the ten Utilities that comprise the Regulated Distribution segment uniquely position this business unit for growth and represents an additional investment opportunity. 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.

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

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Three Months Ended June 30				For the Six Months Ended June 30			
	2017	2016	Change		2017	2016	Change	
REVENUES:	$3,309	$3,401	$(92)	(3)%	$6,861	$7,270	$(409)	(6)%
OPERATING EXPENSES:								
Fuel	343	438	(95)	(22)%	711	819	(108)	(13)%
Purchased power	735	889	(154)	(17)%	1,598	2,013	(415)	(21)%
Other operating expenses	957	964	(7)	(1)%	2,099	1,882	217	12 %
Provision for depreciation	281	334	(53)	(16)%	556	663	(107)	(16)%
Amortization of regulatory assets, net	65	63	2	3 %	124	124	—	— %
General taxes	253	241	12	5 %	524	521	3	1 %
Impairment of assets	131	1,447	(1,316)	(91)%	131	1,447	(1,316)	(91)%
Total operating expenses	2,765	4,376	(1,611)	(37)%	5,743	7,469	(1,726)	(23)%
OPERATING INCOME (LOSS)	544	(975)	1,519	NM	1,118	(199)	1,317	NM
OTHER INCOME (EXPENSE):								
Investment income	17	19	(2)	(11)%	41	47	(6)	(13)%
Interest expense	(290)	(289)	(1)	— %	(577)	(577)	—	— %
Capitalized financing costs	20	26	(6)	(23)%	40	51	(11)	(22)%
Total other expense	(253)	(244)	(9)	4 %	(496)	(479)	(17)	4 %
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	291	(1,219)	1,510	NM	622	(678)	1,300	NM
INCOME TAXES (BENEFITS)	117	(130)	247	NM	243	83	160	NM
NET INCOME (LOSS)	$174	$(1,089)	$1,263	NM	$379	$(761)	$1,140	NM
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:								
Basic	$0.39	$(2.56)	$2.95	NM	$0.86	$(1.79)	$2.65	NM
Diluted	$0.39	$(2.56)	$2.95	NM	$0.85	$(1.79)	$2.64	NM

* NM = not meaningful

For the Three Months Ended June 30, 2017

FirstEnergy’s net income in the second quarter of 2017 was $174 million, or a basic and diluted earnings of $0.39 per share of common stock, compared with a net loss of $(1,089) million, or a basic and diluted loss of $(2.56) per share of common stock in the second quarter of 2016.

The $1,263 million improvement in operating results was primarily due to lower asset impairment and plant exit costs recognized in the second quarter of 2017 as compared to the same period of 2016. In the second quarter of 2017, CES recognized a pre-tax impairment charge of $131 million, resulting from the status of ongoing negotiations regarding the asset purchase agreement between AE Supply, AGC and a subsidiary of LS Power and reflecting the impact of prevailing market conditions as discussed under "Outlook - Asset Impairment - Competitive Generation Asset Sale" below. In the second quarter of 2016, CES recognized pre-tax asset impairment and plant exit costs associated with the following:

- Non-cash impairment charges of $800 million associated with goodwill at CES,
- Non-cash 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 (720 MW) and the Bay Shore Unit 1 generating station (136 MW),
- Coal contract settlement and termination costs of $58 million, and
- Valuation allowances against state and local NOL carryforwards of $159 million.

During the second quarter of 2017, FirstEnergy’s revenues decreased $92 million as compared to the same period in 2016, resulting from a $252 million decrease at CES, partially offset by a $73 million increase at Regulated Distribution and a $52 million increase at Regulated Transmission.

- The decrease in revenue at CES was due to lower capacity revenues from lower capacity auction prices and lower contract sales volumes.
- The increase in revenue at Regulated Distribution primarily resulted from the implementation of the Ohio Companies' DMR effective January 1, 2017, higher revenues from approved base distribution rate increases in Pennsylvania and New Jersey, both effective in January 2017, as well as higher revenues associated with the Ohio Companies' DCR. Distribution deliveries were slightly lower year-over-year mainly from lower weather-related usage and retail generation sales decreased as compared to 2016 resulting from higher customer shopping.
- The increase in revenue at Regulated Transmission resulted from a higher rate base at ATSI and TrAIL as well as recovery of incremental operating expenses.

Operating expenses decreased $1,611 million in the second quarter of 2017 as compared to the second quarter of 2016, primarily reflecting a decrease at CES of $1,662 million. Changes in certain operating expenses include the following:

- Impairment of assets at CES decreased $1,316 million as further described above.
- Fuel expense decreased $95 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts in the second quarter of 2016 and lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices.
- Purchased power decreased $154 million, primarily at CES, due to lower capacity rates as well as lower volumes and market prices. The decline in purchased power at Regulated Distribution was the result of lower volumes from increased customer shopping as well as lower costs reflecting lower default service auction prices.
- Depreciation expense decreased $53 million, primarily due to a lower asset base at CES resulting from asset impairments recognized in 2016.

Other income (expense) increased $9 million primarily from lower capitalized financing costs.

FirstEnergy’s effective tax rate was 40.2% on pre-tax income for the three months ended June 30, 2017 compared to 10.7% on pre-tax losses for the same period in 2016. The change in the effective tax rate resulted from the absence of an $800 million goodwill impairment charge, of which $433 million was non-deductible for tax purposes, and valuation allowances against state and local NOL carryforwards recognized in the second quarter of 2016.

For the Six Months Ended June 30, 2017

For the six months ended June 30, 2017, FirstEnergy’s net income was $379 million, or basic earnings of $0.86 per share of common stock ($0.85 diluted), compared with a net loss of $(761) million, or a basic and diluted loss of $(1.79) per share of common stock, for the six months ended June 30, 2016.

FirstEnergy's earnings for the six months ended June 30, 2017, increased $1,140 million as compared to the same period of 2016 primarily due to lower asset impairment and plant exit costs discussed above.

During the first six months of 2017, FirstEnergy’s revenues decreased $409 million as compared to the same period in 2016, resulting from a $625 million decrease at CES, partially offset by a $53 million increase at Regulated Distribution and a $79 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 increase in revenue at Regulated Distribution primarily resulted from the implementation of the Ohio Companies' DMR effective January 1, 2017, higher revenues from approved base distribution rate increases in Pennsylvania and New Jersey, both effective January 2017, as well as higher revenues associated with the Ohio Companies' DCR. These increases were partially offset by lower generation revenues mainly related to increased customer shopping in Ohio, Pennsylvania, and New Jersey. Additionally, distribution deliveries were slightly lower year-over-year mainly from lower weather-related usage.
- The increase in revenue at Regulated Transmission resulted from a higher rate base at ATSI and TrAIL as well as recovery of incremental operating expenses. Additionally, JCP&L's forward-looking formula rate on transmission assets was implemented on June 1, 2017, subject to refund.

Operating expenses decreased $1,726 million in the first six months of 2017 as compared to the same period of 2016, primarily reflecting a decrease at CES of $1,700 million. Changes in certain operating expenses include the following:

- Impairment of assets at CES decreased $1,316 million as further described above.
- Fuel expense decreased $108 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 and a lower unit costs.

- Purchased power decreased $415 million, primarily at CES, due to lower capacity expense as a result of lower contract sales and lower capacity rates as well as lower volumes and market prices. At Regulated Distribution, the decline in purchased power was the result of lower volumes from increased customer shopping as well as lower costs reflecting lower default service auction prices.
- Other operating expenses increased $217 million, reflecting an increase of $160 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 $25 million at Regulated Distribution resulting primarily from higher operating and maintenance expenses, including increased storm restoration costs.
- Depreciation expense decreased $107 million, primarily due to a lower asset base at CES resulting from asset impairments recognized in 2016.

Other expense increased $17 million, primarily from lower capitalized financing costs.

FirstEnergy's effective tax rate was 39.1% on pre-tax income for the six months ended June 30, 2017 compared to (12.2)% on pre-tax losses for the same period in 2016. The change in the effective tax rate resulted from the absence of an $800 million goodwill impairment charge, of which $433 million was non-deductible for tax purposes, and valuation allowances against state and local NOL carryforwards recognized in the six months ended June 30, 2016.

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 — Second Quarter 2017 Compared with Second Quarter 2016

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

Second Quarter 2017 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,215	$ 327	$ 750	$ (42)	$ 3,250
Other	47	—	28	(16)	59
Internal	—	—	86	(86)	—
Total Revenues	2,262	327	864	(144)	3,309
Operating Expenses:					
Fuel	121	—	222	—	343
Purchased power	657	—	164	(86)	735
Other operating expenses	627	50	349	(69)	957
Provision for depreciation	179	54	29	19	281
Amortization of regulatory assets, net	62	3	—	—	65
General taxes	175	43	27	8	253
Impairment of assets	—	—	131	—	131
Total Operating Expenses	1,821	150	922	(128)	2,765
Operating Income (Loss)	441	177	(58)	(16)	544
Other Income (Expense):					
Investment income (loss)	14	—	12	(9)	17
Interest expense	(134)	(39)	(47)	(70)	(290)
Capitalized financing costs	5	7	7	1	20
Total Other Expense	(115)	(32)	(28)	(78)	(253)
Income (Loss) Before Income Taxes (Benefits)	326	145	(86)	(94)	291
Income taxes (benefits)	121	53	(30)	(27)	117
Net Income (Loss)	$205	$ 92	$ (56)	$ (67)	$ 174

Second Quarter 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,136	$ 275	$ 963	$ (43)	$ 3,331
Other	53	—	45	(28)	70
Internal	—	—	108	(108)	—
Total Revenues	2,189	275	1,116	(179)	3,401
Operating Expenses:					
Fuel	141	—	297	—	438
Purchased power	721	—	276	(108)	889
Other operating expenses	579	37	432	(84)	964
Provision for depreciation	168	46	103	17	334
Amortization of regulatory assets, net	61	2	—	—	63
General taxes	170	36	29	6	241
Impairment of assets	—	—	1,447	—	1,447
Total Operating Expenses	1,840	121	2,584	(169)	4,376
Operating Income (Loss)	349	154	(1,468)	(10)	(975)
Other Income (Expense):					
Investment income (loss)	13	—	18	(12)	19
Interest expense	(148)	(39)	(48)	(54)	(289)
Capitalized financing costs	5	9	9	3	26
Total Other Expense	(130)	(30)	(21)	(63)	(244)
Income (Loss) Before Income Taxes (Benefits)	219	124	(1,489)	(73)	(1,219)
Income taxes (benefits)	80	46	(230)	(26)	(130)
Net Income (Loss)	$139	$ 78	$ (1,259)	$ (47)	$ (1,089)

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Changes Between Second Quarter 2017 and Second Quarter 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$79	$ 52	$ (213)	$ 1	$ (81)
Other	(6)	—	(17)	12	(11)
Internal	—	—	(22)	22	—
Total Revenues	73	52	(252)	35	(92)
Operating Expenses:					
Fuel	(20)	—	(75)	—	(95)
Purchased power	(64)	—	(112)	22	(154)
Other operating expenses	48	13	(83)	15	(7)
Provision for depreciation	11	8	(74)	2	(53)
Amortization of regulatory assets, net	1	1	—	—	2
General taxes	5	7	(2)	2	12
Impairment of assets	—	—	(1,316)	—	(1,316)
Total Operating Expenses	(19)	29	(1,662)	41	(1,611)
Operating Income (Loss)	92	23	1,410	(6)	1,519
Other Income (Expense):					
Investment income (loss)	1	—	(6)	3	(2)
Interest expense	14	—	1	(16)	(1)
Capitalized financing costs	—	(2)	(2)	(2)	(6)
Total Other Expense	15	(2)	(7)	(15)	(9)
Income (Loss) Before Income Taxes (Benefits)	107	21	1,403	(21)	1,510
Income taxes (benefits)	41	7	200	(1)	247
Net Income (Loss)	$66	$ 14	$ 1,203	$ (20)	$ 1,263

Regulated Distribution — Second Quarter 2017 Compared with Second Quarter 2016

Regulated Distribution's operating results increased $66 million in the second 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 higher operating expenses.

Revenues —

The $73 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended June 30 2017	2016	Increase (Decrease)
	(In millions)		
Distribution services	$1,254	$1,080	$ 174
Generation sales:			
Retail	848	936	(88)
Wholesale	113	120	(7)
Total generation sales	961	1,056	(95)
Other	47	53	(6)
Total Revenues	$2,262	$2,189	$ 73

Distribution services revenues increased $174 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 this net rate increase 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 June 30 2017	2016	Increase (Decrease)
	(In thousands)		
Residential	11,115	11,656	(4.6)%
Commercial	10,190	10,349	(1.5)%
Industrial	12,795	12,346	3.6%
Other	138	145	(4.8)%
Total Electric Distribution MWH Deliveries	34,238	34,496	(0.7)%

Lower distribution deliveries to residential and commercial customers primarily reflect lower weather-related usage resulting from heating degree days that were 30% below 2016, and 24% below normal. Cooling degree days in the second quarter of 2017 were flat compared to the same period of 2016 and 10% 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 $95 million decrease in generation revenues for the second 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	$ (47)
Change in prices	(41)
	(88)
Wholesale:	
Effect of decrease in sales volumes	(3)
Change in prices	3
Capacity Revenue	(7)
	(7)
Decrease in Generation Revenues	$ (95)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio and Pennsylvania. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 86% from 82% for the Ohio Companies and to 70% from 69% for the Pennsylvania Companies. The decrease in retail generation prices primarily resulted from lower default service auction prices in Ohio, Pennsylvania, and New Jersey.

Operating Expenses —

Total operating expenses decreased $19 million primarily due to the following:

- Fuel expense decreased $20 million in the second quarter of 2017, as compared to the same period in 2016, primarily related to lower unit costs.

- Purchased power costs were $64 million lower in the second quarter of 2017, as compared to the same period in 2016, primarily due to lower unit costs reflecting lower default service auction prices as well as decreased volumes resulting from increased customer shopping, as described above.

Source of Change in Purchased Power	Increase(Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (51)
Change due to decreased volumes	(20)
	(71)
Purchases from affiliates:	
Change due to decreased unit costs	(6)
Change due to decreased volumes	(15)
	(21)
Capacity Expense	(5)
Amortization of deferred costs	33
Decrease in Purchased Power Costs	$ (64)

- Other operating expenses increased $48 million primarily due to:
  - Higher operating and maintenance expenses of $39 million, including increased storm restoration costs, which were deferred for future recovery, resulting in no material impact on current period earnings, and increased expenses in Pennsylvania recovered through new base distribution rates effective January 27, 2017.
  - Higher transmission expenses of $7 million primarily due to an increase in network transmission expenses. The difference between current revenues and transmission costs incurred are deferred for future recovery or refund, resulting in no material impact on current period earnings.

- Depreciation expense increased $11 million primarily due to a higher asset base as well as increased rates in Pennsylvania.

Other Expense —

Other expenses decreased $15 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 37.1% and 36.5% for the quarter ended June 30, 2017 and 2016, respectively.

Regulated Transmission — Second Quarter 2017 Compared with Second Quarter 2016

Regulated Transmission's operating results increased $14 million in the second quarter of 2017 compared to the same period of 2016 primarily resulting from a higher rate base at ATSI and TrAIL as well as the absence of adjustments recognized in 2016 that lowered revenue associated with ATSI and TrAIL's annual rate filings. Additionally, JCP&L's forward-looking formula rates for its transmission assets were implemented on June 1, 2017, subject to refund pending further FERC hearing and settlement procedures.

Revenues —

Total revenues increased $52 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL.

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

	For the Three Months Ended June 30		
Revenues by Transmission Asset Owner	2017	2016	Increase (Decrease)
	(In millions)		
ATSI	$164	$128	$ 36
TrAIL	73	59	14
MAIT [(1)]	24	26	(2)
JCP&L	27	23	4
Other	39	39	—
Total Revenues	$327	$275	$ 52

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

Operating Expenses —

Total operating expenses increased $29 million principally due to higher operating and maintenance expenses, as well as higher property taxes and depreciation due to higher asset base.

Other Expense —

Total other expense increased $2 million in the second quarter of 2017 as compared to the same period of 2016 primarily due to lower capitalized financing costs.

Income Taxes —

Regulated Transmission's effective tax rate was 36.6% and 37.1% for the quarter ended June 30, 2017 and 2016, respectively.

CES — Second Quarter 2017 Compared with Second Quarter 2016

CES' operating results increased $1,203 million in the second quarter of 2017, compared to the same period of 2016, primarily due to lower asset impairment and plant exit costs, as discussed above, lower depreciation expense, and lower non-cash mark-to-market losses on commodity contract positions, partially offset by lower capacity revenue due to lower capacity auction prices.

Revenues —

Total revenues decreased $252 million in the second quarter of 2017, compared to the same period of 2016, primarily due to lower capacity revenues from lower capacity auction prices and lower contract sales volumes, 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 June 30 2017	2016	Decrease
	(In millions)		
Contract Sales:			
Direct	$187	$196	$ (9)
Governmental Aggregation	83	191	(108)
Mass Market	28	37	(9)
POLR	114	125	(11)
Structured Sales	79	115	(36)
Total Contract Sales	491	664	(173)
Wholesale	332	389	(57)
Transmission	13	18	(5)
Other	28	45	(17)
Total Revenues	$864	$1,116	$ (252)

MWH Sales by Channel	For the Three Months Ended June 30 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	3,919	3,684	6.4 %
Governmental Aggregation	1,617	2,991	(45.9)%
Mass Market	404	536	(24.6)%
POLR	2,049	2,081	(1.5)%
Structured Sales	1,956	2,842	(31.2)%
Total Contract Sales	9,945	12,134	(18.0)%
Wholesale	5,934	3,577	65.9 %
Total MWH Sales	15,879	15,711	1.1 %

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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	$13	$(22)	$ —	$ —	$(9)
Governmental Aggregation	(88)	(20)	—	—	(108)
Mass Market	(9)	—	—	—	(9)
POLR	(2)	(9)	—	—	(11)
Structured Sales	(36)	—	—	—	(36)
Wholesale	59	23	(44)	(95)	(57)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract during 2016. The Direct, Governmental Aggregation and Mass Market customer base was approximately 850,000 as of June 30, 2017, compared to 1.5 million as of June 30, 2016. Although unit pricing 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.

Structured Sales decreased $36 million due to the impact of lower structured transaction volumes.

Wholesale revenues decreased $57 million, primarily due to a decrease in capacity revenue from capacity auctions 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 $5 million, primarily due to lower congestion revenue.

Other revenue decreased $17 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 $1,662 million in the second quarter of 2017 due to the following:

- Fuel costs decreased $75 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts in the second quarter of 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 on fossil fuel contracts.
- Purchased power costs decreased $112 million due to lower capacity expense ($96 million) and lower unit costs ($42 million), partially offset by higher volumes ($26 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 obligation. Higher volumes primarily resulted from increased economic purchases at lower unit costs.
- Fossil operating and maintenance expenses decreased $19 million, primarily due to lower outage costs.
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Nuclear operating and maintenance expenses increased $17 million, primarily as a result of higher refueling outage costs. There were two refueling outages during the second quarter of 2017, as compared to one refueling outage during the same period of 2016.

- Transmission expenses decreased $11 million, primarily due to lower load requirements.

- Other operating expenses decreased $68 million, primarily due to lower non-cash mark-to-market losses on commodity contract positions.

- Depreciation expense decreased $74 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016.

- Impairment of assets decreased $1,316 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 a $131 million impairment charge recognized in the second quarter of 2017 resulting from the status of ongoing negotiations regarding the asset purchase agreement between AE Supply, AGC, and a subsidiary of LS Power and reflecting the impact of prevailing market conditions as further discussed under "Outlook - Asset Impairment - Competitive Generation Asset Sale" below.

Other Expense —

Total other expense increased $7 million in the second quarter of 2017, as compared to the same period of 2016, primarily due to higher OTTI and lower investment income on NDT investments.

Income Taxes —

CES' effective tax rate was 34.9% on pre-tax income and 15.4% on pre-tax losses for the quarter ended June 30, 2017 and 2016, respectively. The change in the effective tax rate is primarily due to the impairment of $800 million of goodwill 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.

Corporate / Other — Second Quarter 2017 Compared with Second 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 $20 million decrease in consolidated earnings in the second quarter of 2017, compared to the same period of 2016, primarily associated with higher interest expense resulting from higher average borrowings on the FE revolving credit facility and the issuance of $3 billion of senior notes in June of 2017.

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

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

First Six Months 2017 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,659	$ 640	$ 1,523	$ (84)	$ 6,738
Other	93	—	69	(39)	123
Internal	—	—	203	(203)	—
Total Revenues	4,752	640	1,795	(326)	6,861
Operating Expenses:					
Fuel	262	—	449	—	711
Purchased power	1,470	—	331	(203)	1,598
Other operating expenses	1,251	95	913	(160)	2,099
Provision for depreciation	357	105	57	37	556
Amortization of regulatory assets, net	119	5	—	—	124
General taxes	359	85	57	23	524
Impairment of assets	—	—	131	—	131
Total Operating Expenses	3,818	290	1,938	(303)	5,743
Operating Income (Loss)	934	350	(143)	(23)	1,118
Other Income (Expense):					
Investment income (loss)	28	—	32	(19)	41
Interest expense	(272)	(78)	(92)	(135)	(577)
Capitalized financing costs	11	13	15	1	40
Total Other Expense	(233)	(65)	(45)	(153)	(496)
Income (Loss) Before Income Taxes (Benefits)	701	285	(188)	(176)	622
Income taxes (benefits)	259	105	(65)	(56)	243
Net Income (Loss)	$442	$ 180	$ (123)	$ (120)	$ 379

First Six Months 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,567	$ 561	$ 2,064	$ (89)	$ 7,103
Other	132	—	96	(61)	167
Internal	—	—	260	(260)	—
Total Revenues	4,699	561	2,420	(410)	7,270
Operating Expenses:					
Fuel	280	—	539	—	819
Purchased power	1,647	—	626	(260)	2,013
Other operating expenses	1,226	74	753	(171)	1,882
Provision for depreciation	335	91	205	32	663
Amortization of regulatory assets, net	120	4	—	—	124
General taxes	355	77	68	21	521
Impairment of assets	—	—	1,447	—	1,447
Total Operating Expenses	3,963	246	3,638	(378)	7,469
Operating Income (Loss)	736	315	(1,218)	(32)	(199)
Other Income (Expense):					
Investment income (loss)	24	—	33	(10)	47
Interest expense	(298)	(79)	(95)	(105)	(577)
Capitalized financing costs	9	16	20	6	51
Total Other Expense	(265)	(63)	(42)	(109)	(479)
Income (Loss) Before Income Taxes (Benefits)	471	252	(1,260)	(141)	(678)
Income taxes (benefits)	174	93	(145)	(39)	83
Net Income (Loss)	$297	$ 159	$ (1,115)	$ (102)	$ (761)

Changes Between First Six Months 2017 and First Six Months 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$92	$ 79	$ (541)	$ 5	$ (365)
Other	(39)	—	(27)	22	(44)
Internal	—	—	(57)	57	—
Total Revenues	53	79	(625)	84	(409)
Operating Expenses:					
Fuel	(18)	—	(90)	—	(108)
Purchased power	(177)	—	(295)	57	(415)
Other operating expenses	25	21	160	11	217
Provision for depreciation	22	14	(148)	5	(107)
Amortization of regulatory assets, net	(1)	1	—	—	—
General taxes	4	8	(11)	2	3
Impairment of assets	—	—	(1,316)	—	(1,316)
Total Operating Expenses	(145)	44	(1,700)	75	(1,726)
Operating Income (Loss)	198	35	1,075	9	1,317
Other Income (Expense):					
Investment income (loss)	4	—	(1)	(9)	(6)
Interest expense	26	1	3	(30)	—
Capitalized financing costs	2	(3)	(5)	(5)	(11)
Total Other Expense	32	(2)	(3)	(44)	(17)
Income (Loss) Before Income Taxes (Benefits)	230	33	1,072	(35)	1,300
Income taxes (benefits)	85	12	80	(17)	160
Net Income (Loss)	$145	$ 21	$ 992	$ (18)	$ 1,140

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

Regulated Distribution's operating results increased $145 million in the first six months 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. 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 $53 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Six Months Ended June 30 2017	2016	Increase (Decrease)
	(In millions)		
Distribution services	$2,562	$2,236	$ 326
Generation sales:			
Retail	1,860	2,089	(229)
Wholesale	237	242	(5)
Total generation sales	2,097	2,331	(234)
Other	93	132	(39)
Total Revenues	$4,752	$4,699	$ 53

Distribution services revenues increased $326 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 revenues from the DCR in Ohio. Partially offsetting this net rate increase 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 Six Months Ended June 30 2017	2016	Increase (Decrease)
	(In thousands)		
Residential	24,983	25,992	(3.9)%
Commercial	20,465	20,908	(2.1)%
Industrial	25,399	24,724	2.7 %
Other	281	292	(3.8)%
Total Electric Distribution MWH Deliveries	71,128	71,916	(1.1)%

Lower distribution deliveries to residential and commercial customers primarily reflect lower weather-related usage resulting from heating degree days that were 12% below 2016, and 17% below 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 $234 million decrease in generation revenues for the first six 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	$ (137)
Change in prices	(92)
	(229)
Wholesale:	
Effect of increase in sales volumes	17
Change in prices	(2)
Capacity Revenue	(20)
	(5)
Decrease in Generation Revenues	$ (234)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio and Pennsylvania. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 85% from 81% for the Ohio Companies and to 69% from 67% for the Pennsylvania Companies. The decrease in retail generation prices primarily resulted from lower default service auction prices in Ohio, Pennsylvania, and New Jersey.

Other revenues decreased $39 million primarily related to a $26 million gain on the sale of oil and gas rights at WP recognized in 2016.

Operating Expenses —

Total operating expenses decreased $145 million primarily due to the following:

- Fuel expense decreased $18 million in the six months of 2017, as compared to the same period in 2016, primarily related to lower unit costs.

- Purchased power costs decreased $177 million during the first six months of 2017, as compared to the same period of 2016 primarily due to decreased volumes resulting from increased customer shopping, as described above, as well as lower unit costs reflecting lower default service auction prices.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (97)
Change due to volumes	(75)
	(172)
Purchases from affiliates:	
Change due to decreased unit costs	(16)
Change due to volumes	(40)
	(56)
Capacity Expense	(16)
Amortization of deferred costs	67

Decrease in Purchased Power Costs	$	(177)

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- Other operating expenses increased $25 million primarily due to:
  - Higher operating and maintenance expenses of $67 million, including increased storm restoration costs of $25 million, which were deferred for future recovery, resulting in no material impact on current period earnings, and increased operating and maintenance expenses in Pennsylvania recovered through the new base distribution rates effective January 27, 2017.
  - Higher transmission expenses of $8 million primarily due to an increase in network transmission expenses. 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.
  - 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 $22 million primarily due to a higher rate base as well as increased rates in Pennsylvania.

Other Expense —

Total other expense decreased $32 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 36.9% for the first six months of 2017 and 2016, respectively.

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

Regulated Transmission's operating results increased $21 million in the first six months of 2017, compared to the same period of 2016, primarily resulting from a higher rate base at ATSI and TrAIL as well as the absence of adjustments recognized in 2016 that lowered revenue associated with ATSI and TrAIL's annual rate filings. Additionally, JCP&L's forward-looking formula rates for its transmission assets were implemented on June 1, 2017, subject to refund pending further FERC hearing and settlement procedures.

Revenues —

Total revenues increased $79 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL.

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

Revenues by Transmission Asset Owner	For the Six Months Ended June 30 2017	2016	Increase (Decrease)
	(In millions)		
ATSI	$317	$262	$ 55
TrAIL	144	120	24
MAIT [1]	49	53	(4)
JCP&L	50	46	4

Other	80	80	—
Total Revenues	$640	$561	$ 79

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

Operating Expenses —

Total operating expenses increased $44 million principally due to higher operating and maintenance expenses, as well as higher property taxes and depreciation due to higher asset base.

Income Taxes —

Regulated Transmission's effective tax rate was 36.8% and 36.9% for the first six months of 2017 and 2016, respectively.

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

CES' operating results increased $992 million in the first six months of 2017, 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 due to lower capacity auction prices.

Revenues —

Total revenues decreased $625 million in the first six months of 2017, compared to the same period of 2016, primarily due to lower capacity revenues from lower capacity auction prices, lower contract sales volume 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 Six Months Ended June 30 2017	2016	Decrease
	(In millions)		
Contract Sales:			
Direct	$387	$403	$ (16)
Governmental Aggregation	194	432	(238)
Mass Market	65	85	(20)
POLR	268	282	(14)
Structured Sales	159	277	(118)
Total Contract Sales	1,073	1,479	(406)
Wholesale	628	806	(178)
Transmission	25	39	(14)
Other	69	96	(27)
Total Revenues	$1,795	$2,420	$ (625)

MWH Sales by Channel	For the Six Months Ended June 30 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	7,859	7,478	5.1 %
Governmental Aggregation	3,754	6,560	(42.8)%
Mass Market	947	1,239	(23.6)%
POLR	4,813	4,633	3.9 %
Structured Sales	3,907	6,738	(42.0)%
Total Contract Sales	21,280	26,648	(20.1)%
Wholesale	10,389	5,490	89.2 %
Total MWH Sales	31,669	32,138	(1.5)%

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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	$20	$(36)	$ —	$ —	$(16)
Governmental Aggregation	(185)	(53)	—	—	(238)
Mass Market	(20)	—	—	—	(20)
POLR	11	(25)	—	—	(14)
Structured Sales	(116)	(2)	—	—	(118)
Wholesale	132	24	(90)	(244)	(178)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract during 2016. Although unit pricing 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 sales of $14 million was primarily due to lower unit prices, partially offset by higher volumes. Structured Sales decreased $118 million, primarily due to the impact of lower transaction volumes.

Wholesale revenues decreased $178 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 $14 million, primarily due to lower congestion revenue.

Other revenue decreased $27 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 $1,700 million in the first six months of 2017, compared to the same period of 2016, due to the following:

- Fuel costs decreased $90 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts 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 on fossil fuel contracts.
- Purchased power costs decreased $295 million, primarily due to lower capacity expenses ($234 million) and lower unit costs ($66 million), partially offset by higher volumes ($5 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 and increased economic purchases, as discussed above.
- A $164 million charge associated with estimated losses on long-term coal transportation contract disputes recognized in the first quarter of 2017 as discussed in "Outlook - Environmental Matters" below.

- Fossil operating and maintenance expenses decreased $43 million, primarily due to lower outage costs.

- Nuclear operating and maintenance expenses increased $24 million, primarily as a result of higher refueling outage costs. There were two refueling outages during the first six months of 2017, as compared to one refueling outage during the same period of 2016.

- Transmission expenses decreased $26 million, primarily due to lower load requirements.

- Other operating expenses increased $43 million, primarily due to higher non-cash mark-to-market losses on commodity contract positions.

- Depreciation expense decreased $148 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016.
- General taxes decreased $11 million, primarily due to lower gross receipts taxes associated with lower retail sales volumes.
- Impairment of assets decreased $1,316 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 a $131 million impairment charge recognized in the second quarter of 2017 resulting from the status of ongoing negotiations regarding the asset purchase agreement between AE Supply, AGC, and a subsidiary of LS Power and reflecting the impact of prevailing market conditions as further discussed under "Outlook - Asset Impairment - Competitive Generation Asset Sale" below.

Income Taxes (Benefits) —

CES' effective tax rate was 34.6% on pre-tax income and 11.5% on pre-tax losses for the first six months of 2017 and 2016, respectively. The change in the effective tax rate is primarily due to the impairment of $800 million of goodwill 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.

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

Financial results from the Corporate/Other operating segment and reconciling adjustments resulted in a $18 million decrease in consolidated earnings in the first six months of 2017 compared to the same period of 2016 primarily associated with higher interest expense resulting 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 June 30, 2017 and December 31, 2016, and the changes during the six months ended June 30, 2017:

Net Regulatory Assets by Source	June 30, 2017	December 31, 2016	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$58	$ 90	$ (32)
Customer receivables for future income taxes	370	444	(74)
Nuclear decommissioning and spent fuel disposal costs	(170)	(304)	134
Asset removal costs	(340)	(470)	130
Deferred transmission costs	163	127	36
Deferred generation costs	216	215	1
Deferred distribution costs	248	296	(48)
Contract valuations	99	153	(54)
Storm-related costs	305	353	(48)
Other	45	110	(65)
Net Regulatory Assets included on the Consolidated Balance Sheets	$994	$ 1,014	$ (20)

Regulatory assets that do not earn a current return totaled approximately $107 million and $153 million as of June 30, 2017 and December 31, 2016, respectively, primarily related to storm damage costs and are currently being recovered through rates.

As of June 30, 2017, and December 31, 2016, FirstEnergy had approximately $259 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, including cash requirements to fund Regulated Transmission's capital program, may be met through a combination of an additional $500 million of equity in each year 2017 through 2019, and new long-term debt, in each case, subject to market conditions and other factors. FirstEnergy also expects to issue long-term debt at certain Utilities to, among other things, refinance short-term and maturing long-term debt, subject to market conditions and other factors.

FirstEnergy’s unregulated subsidiaries, specifically FES and AE Supply, expect to rely on, in the case of AE Supply, internal sources, the unregulated companies' money pool, and proceeds generated from previously disclosed asset sales, subject to closing, and 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. 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.

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.

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

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 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 June 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 June 30, 2017, included the following:

Currently Payable Long-Term Debt	(In millions)
Unsecured notes	$ 1,100
FMBs	575
Secured PCRBs	141
Unsecured PCRBs	99
Sinking fund requirements	60
Other notes	40
	$ 2,015

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 $225 million and $2,675 million of short-term borrowings as of June 30, 2017 and December 31, 2016, respectively. FirstEnergy’s available liquidity from external sources as of June 30, 2017 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity [(3)]
			(In millions)	
FirstEnergy[(1)]	Revolving	December 2021	$4,000	$ 3,840
FET[(2)]	Revolving	December 2021	1,000	925
		Subtotal	$5,000	$ 4,765
		Cash	—	114
		Total	$5,000	$ 4,879

(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 June 30, 2017, FE and its subsidiaries could issue additional debt of approximately $4.4 billion and remain within the limitations of the financial covenants required by the FE Facility.

FES had $275 million and $101 million of short-term borrowings as of June 30, 2017 and December 31, 2016, respectively. Of such amounts, $102 million and $101 million, respectively, represents a currently outstanding promissory note due August 31, 2017 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 June 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 June 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 June 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, and a $12 million FES surety bond for the benefit of the Ohio Environmental Protection Agency relating to the W.H. Sammis generating station. As of

June 30, 2017, an additional $19 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 June 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. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first six months of 2017 was 1.47% per annum for the regulated companies' money pool and 2.41% 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 the DOE study. As of June 30, 2017, FES, its subsidiaries and FENOC had $174 million of net borrowings in the aggregate under the unregulated companies' money pool.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of June 30, 2017:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody's	Fitch	S&P	Moody's	Fitch
FE	—	—	—	BB+	Baa3	BBB-
FES	B-	B1	—	CCC	Caa1	C
AE Supply	BB	—	BB	BB-	B1	BB-
AGC	—	—	—	BB-	Baa3	BB
ATSI	—	—	—	BBB-	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 June 30, 2017, FE and its subsidiaries could issue additional debt of approximately $4.4 billion or incur a $2.4 billion reduction to equity, and remain within the limitations of the financial covenants required by the FE Facility.

Changes in Cash Position

As of June 30, 2017, FirstEnergy had $114 million of cash and cash equivalents compared to $199 million of cash and cash equivalents as of December 31, 2016. As of June 30, 2017 and December 31, 2016, FirstEnergy had approximately $57 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 $1,482 million during the first six months of 2017 compared with $1,472 million provided from operating activities during the first six months of 2016. Key changes in cash flows from operations in the first six months of 2017, compared with the same period of 2016, primarily were as follows:

- The absence of $160 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 collections of capacity revenue at CES.

Cash Flows From Financing Activities

In the first six months of 2017, cash used for financing activities was $56 million compared to $363 million of cash provided from financing activities during the first six months of 2016. The following table summarizes redemptions, repayments, short-term borrowings and dividends:

Securities Issued or Redeemed / Repaid	For the Six Months Ended June 30 2017	2016
	(In millions)	
New Issues		
Term Loan	$250	$—
Unsecured Notes	3,000	—
FMBs	250	—
	$3,500	$—
Redemptions / Repayments		
PCRBs	(158)	—
Unsecured notes	(380)	(356)
FMBs	(150)	—
Senior secured notes	(47)	(225)
	$(735)	$(581)
Short-term borrowings (repayments), net	$(2,450)	$1,225
Common stock dividend payments	$(319)	$(305)

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 2018 on July 25, 2017 and (ii) for general corporate purposes, including the repayment of short-term borrowings under the FE Facility.

Cash Flows From Investing Activities

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

Cash Used for Investing Activities	For the Six Months Ended June 30 2017	2016	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$568	$528	$ 40
Regulated Transmission	469	556	(87)
Competitive Energy Services	188	382	(194)
Corporate / Other	29	26	3
Nuclear fuel	134	188	(54)
Investments	48	49	(1)
Asset removal costs	79	63	16
Other	(4)	(25)	21
	$1,511	$1,767	$ (256)

Cash used for investing activities for the first six months of 2017 decreased $256 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 $194 million at CES, resulting from lower capital investments associated with outages, MATS compliance, and the Mansfield dewatering facility,
- a decrease of $87 million at Regulated Transmission due to timing of capital investments associated with its Energizing the Future investment program; partially offset by,
- an increase of $40 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 June 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)]	195
Surety Bonds	203
Sale leaseback indemnity	58
LOCs[(7)]	10
	466
Total Guarantees and Other Assurances	$ 3,280

(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 is a guarantor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR and a guarantor for a $12 million FES surety bond for the benefit of the Ohio Environmental Protection Agency relating to the W.H. Sammis generating station under the surety support provisions of FE's credit facility to FES as discussed above. As of June 30, 2017, an additional $19 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 June 30, 2017, FES has posted collateral of $123 million and AE Supply has posted no collateral. The Regulated Distribution Segment has posted collateral of $4 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of June 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	—	—	43	—	43
Surety Bonds (Collateralized Amount)[(1)]	65	25	92	187	369
Total Exposure from Contractual Obligations	$71	$ 27	$ 135	$187	$420

[(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 is a guarantor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR and a guarantor for a $12 million FES surety bond for the benefit of the Ohio Environmental Protection Agency relating to the W.H. Sammis generating station.

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of June 30, 2017, FES has $2 million collateral posted with their 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 $859 million as of June 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 June 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 June 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]	$—	$(20)	$(34)	$(11)	$ —	$ —	$(65)
Prices based on models	(1)	2	—	—	—	—	1
Total[2]	$(1)	$(18)	$(34)	$(11)	$ —	$ —	$(64)

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

(2) Includes $(98) 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 June 30, 2017, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $15 million during the next twelve months.

Equity Price Risk

As of June 30, 2017, the FirstEnergy pension plan assets were allocated approximately as follows: 43% in equity securities, 35% in fixed income securities, 8% 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 six months ended June 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 June 30, 2017, FirstEnergy's pension plan assets earned approximately 8.4% as compared to an annual expected return on plan assets of 7.5%.

As of June 30, 2017, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through June 30, 2017 FirstEnergy's OPEB plans have earned approximately 5.9% 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 June 30, 2017, approximately 57% of the funds were invested in fixed income securities, 39% 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 $1,497 million, $1,002 million and $104 million for fixed income securities, equity securities and short-term investments, respectively, as of June 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 $100 million reduction in fair value as of June 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 six months ended June 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. At this time, FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 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 $52 million was incurred through June 30, 2017. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE.

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

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

NEW JERSEY

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

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 this generic CTA proceeding to the New Jersey Superior Court and JCP&L filed to participate as a respondent in that proceeding supporting the order. Briefing was completed, and the oral argument was held on October 25, 2016.

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 December 7, 2016, the PUCO granted the applications for rehearing for further consideration of the matters specified in the applications for rehearing. The matter remains pending before the PUCO. For additional information, see "FERC Matters - Ohio ESP IV PPA" below.

Under ORC 4928.66, the Ohio Companies 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 SB 310 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. There is an additional application for rehearing that remains pending before the PUCO.

PENNSYLVANIA

The Pennsylvania Companies previously operated under DSPs that expired on May 31, 2017, and provided for the competitive procurement of generation supply for customers that did not choose an alternative EGS or for customers of alternative EGSs that failed to provide the contracted service. The Pennsylvania Companies currently 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 current 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.

ME, PN, Penn and WP currently 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 October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.3 million; PN $56.7 million; Penn $56.4 million; and ME $43.4 million, which were approved by the PPUC on February 11, 2016. On March 1, 2017, ME, PN and Penn filed petitions with the PPUC to modify their LTIIPs for the four remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. ME proposed to increase its LTIIP spending by $8.2 million per year, PN by $3.3 million per year, and Penn by $2.5 million per year. The petitions were approved by the PPUC in an Order entered June 14, 2017.

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 and briefing has been completed.

WEST VIRGINIA

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

On September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement by the parties to the proceeding, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year.

On December 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 applications with the WVPSC and MP and AE Supply filed with FERC requesting authorization for such purchase. The WVPSC has scheduled a hearing on this matter for September 26-28, 2017, and public hearings for 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. With respect to the Bath County RFP, MP does not plan to move forward with the sale of its ownership interest. In the future, MP may re-evaluate its options with respect to its interest in Bath County.

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. 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, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which FERC denied on May 19, 2016. 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. On a related issue, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

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

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

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. The settlement process is ongoing.

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.

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 subsequently 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. The requests for rehearing and the compliance filing remain pending before FERC.

Market-Based Rate Authority, Triennial Update

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

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. 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 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. Depending on the outcome of the appeals and on how the EPA and the states implement CSAPR, the future cost of compliance may be material and changes to

FirstEnergy's and FES' operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but the EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State 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 July 20, 2017, the State of Maryland notified the EPA of its intent to sue the EPA for failing to act on Maryland’s CAA Section 126 petition following the 60 day notification period required by the CAA. 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 arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, all plants covered by this contract were deactivated by April 16, 2015. 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, agree 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, 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 does 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. FirstEnergy, FES 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. FirstEnergy and FES dispute the allegations and intend to vigorously defend the merits of the lawsuit. At this time, FirstEnergy and FES 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 United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. The EPA released its final regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA’s state specific CO_2 emission rate goals. The EPA’s CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2016, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. 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. 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. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

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

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

Regulation of Waste Disposal

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

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although not currently expected, any changes in timing and closure plan requirements in the future, including changes resulting from the strategic review at CES, could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The CCRs from the Bruce Mansfield plant are being beneficially reused with the majority used for reclamation of a site owned by the Marshall County Coal Company in Moundsville, W. Va. and the remainder recycled into drywall by National Gypsum. These beneficial reuse options should be sufficient for ongoing plant operations, however, the Bruce Mansfield plant is pursuing other options. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notices of Appeal with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of June 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 June 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 June 30, 2017, FirstEnergy had approximately $2.6 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs 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 upgrades at FirstEnergy’s nuclear facilities have been implemented, the improvements still remain subject to regulatory approval.

FES provides a parental support agreement to NG of up to $400 million. The NRC typically relies on such parental support agreements to provide additional assurance that U.S. merchant nuclear plants, including NG's nuclear units, have the necessary financial resources to maintain safe operations, particularly in the event of extraordinary circumstances. 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

As disclosed in Note 1, "Organization and Basis of Presentation," FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement to sell four of AE Supply’s natural gas generating plants and approximately 59% of AGC’s interest in 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, third party consents, and the satisfaction and discharge of $305 million of AE Supply senior notes, which would require the payment of a "make-whole" premium estimated to be approximately $100 million based on current interest rates. Additionally, as a further condition to closing, FE will provide the purchaser two limited guarantees of certain obligations of AE Supply and AGC arising under the purchase agreement. On February 17, 2017, AE Supply and AGC submitted a filing with FERC and on June 13, 2017, FERC issued an order authorizing the transaction as requested. The parties will also file a request for authorization to transfer the hydroelectric license 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 May 24, 2017, AE Supply and AGC and LS Power exercised a provision in the purchase agreement that allows either party to terminate the purchase agreement without penalty after June 23, 2017. All parties continue to negotiate, including consideration of various alternative structures regarding pricing and closing, and neither party has elected its termination rights under the provisions of the purchase agreement. As a result of the status of these ongoing negotiations regarding the asset purchase agreement and reflecting the impact of prevailing market conditions, CES recorded a non-cash pre-tax impairment charge of $131 million in the second quarter of 2017. FirstEnergy is targeting to close the transaction with revised terms in the second half of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents. There can be no assurance that any such approvals will be obtained and/or any such conditions will be satisfied or that such sale will be consummated.

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 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 statement 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. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard, which will be heavily dependent on the resolution of certain industry issues. 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. FES purchases the entire output of the generation facilities owned by FG and NG, and purchases the uncommitted output of AE Supply, as well as prior to June 1, 2017 the output relating to leasehold interests of OE and TE in certain of those facilities that were subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs. Prior to April 1, 2016, FES financially purchased the uncommitted output of AE Supply's generation facilities under a PSA. On December 21, 2015, FES agreed, under a PSA, to physically purchase all the output of AE Supply's generation facilities effective April 1, 2016. FES and AE Supply terminated the PSA effective 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 prolonged decrease in demand and excess generation supply in the PJM Region, which has resulted in a period of protracted low power and capacity prices. To address this, FES sold or deactivated approximately 2,700 MWs of competitive generation from 2012 to 2015 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 continue to be weak, as evidenced by the significantly depressed 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 the recently announced directive by the Secretary of Energy to complete a study that explores critical issues central to protecting the long-term reliability of the electric grid, including the impact of federal policy interventions and the changing nature of electricity fuel mix, compensation of on-site fuel supply and other factors that strengthen grid resilience, and the impact of regulatory burdens, mandates and tax and subsidy policies on the premature retirement of baseload power plants;
- The resolution of legislation before the Ohio General Assembly that would create a zero-emission nuclear (ZEN) credit that would compensate nuclear power plants for their environmental attributes 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 negative outlook from each of the rating agencies 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 35-40 million MWHs in 2018. While the reduced contract sales will decrease potential collateral requirements, market price volatility may significantly impact FES' financial results due to the increased exposure to the wholesale spot market.

Although FES has access to a $500 million secured line of credit with FE, all of which was available as of June 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 more than sufficient to fund capital expenditures and nuclear fuel purchases through March 2018. As previously disclosed, FES has $515 million of maturing debt in 2018, beginning in the second quarter. 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, even on a secured basis. 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 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" and "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 $246 million in the first six months of 2017, compared to the same period of 2016, primarily due to the absence of asset impairment and plant exit costs 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 due to lower capacity auction prices.

Revenues -

Total revenues decreased $646 million in the first six 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 Six Months Ended June 30 2017	2016	Decrease
	(In millions)		
Contract Sales:			
Direct	$387	$402	$ (15)
Governmental Aggregation	193	431	(238)
Mass Market	65	85	(20)
POLR	268	282	(14)
Structured Sales	149	265	(116)
Total Contract Sales	1,062	1,465	(403)
Wholesale	509	712	(203)
Transmission	23	37	(14)
Other	61	87	(26)
Total Revenues	$1,655	$2,301	$ (646)

MWH Sales by Channel	For the Six Months Ended June 30 2017	2016	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	7,859	7,478	5.1 %
Governmental Aggregation	3,754	6,560	(42.8)%
Mass Market	947	1,239	(23.6)%
POLR	4,813	4,632	3.9 %
Structured Sales	3,740	6,534	(42.8)%
Total Contract Sales	21,113	26,443	(20.2)%
Wholesale	7,897	3,959	99.5 %
Total MWH Sales	29,010	30,402	(4.6)%

The following table summarizes the price and volume factors contributing to changes in revenues in the first six 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	$21	$(36)	$ —	$ —	$(15)
Governmental Aggregation	(185)	(53)	—	—	(238)
Mass Market	(20)	—	—	—	(20)

POLR	11	(25)	—	—	(14)
Structured Sales	(113)	(3)	—	—	(116)
Wholesale	98	25	(90)	(236)	(203)

Lower sales volumes in the Governmental Aggregation channel primarily reflects the termination of an FES customer contract during 2016. The Direct, Governmental Aggregation and Mass Market customer base was approximately 850,000 as of June 30, 2017, compared to 1.5 million as of June 30, 2016. Although unit pricing 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 sales of $14 million was primarily due to lower unit prices, partially offset by higher volumes. Structured Sales decreased $116 million, primarily due to the impact of lower transaction volumes.

Wholesale revenues decreased $203 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 $14 million, primarily due to lower congestion revenues.

Other revenues decreased $26 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 $935 million in the first six 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 six 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	$(36)	$ (2)	$ (58)	$ —	$(96)
Nuclear Fuel	(1)	2	—	—	1
Affiliated Purchased Power	101	(5)	(143)	—	(47)
Non-affiliated Purchased Power	(44)	22	(72)	(233)	(327)

Fossil and nuclear fuel costs decreased $95 million, primarily due to the absence of approximately $58 million in settlement and termination costs on coal contracts 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.

Affiliated purchased power costs decreased $47 million, primarily resulting from the termination of the AE Supply PSA, effective April 1, 2017.

Non-affiliated purchased power costs decreased $327 million due to lower capacity expenses ($233 million) and lower volumes ($44 million) at lower unit costs ($50 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 and unit costs 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 $195 million in the first six 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 recognized in the first quarter of 2017 as discussed in "Outlook - Environmental Matters" above.

- Fossil operating and maintenance expenses decreased $34 million, primarily due to lower outage costs.

- Nuclear operating and maintenance expenses increased $24 million, primarily as a result of higher refueling outage costs. There were two refueling outages during the first six months of 2017, as compared to one refueling outage during the same period of 2016.

- Transmission expenses decreased $22 million, primarily due to lower load requirements.

- Other operating expenses increased $64 million, primarily due to higher non-cash mark-to-market losses on commodity contract positions.

Depreciation expense decreased $115 million, primarily due to a lower asset base resulting from asset impairments recognized in 2016.

Impairment of assets decreased $540 million 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 in 2016.

Income Tax Benefits —

FES' effective tax rate for the six months ended June 30, 2017 and 2016 was 22.8% on pre-tax income and 16.6% on pre-tax losses, respectively. The change in the effective tax rate is primarily due to valuation allowances of $65 million recorded against state and local NOL carryforwards, both of which were recognized in 2016, as well as the impairment of goodwill of $23 million, which is 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 beginning in the second quarter of 2018. 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 negative outlook from each of the rating agencies has challenged its ability to hedge generation with retail and forward wholesale sales without collateral obligations, which reduce the business units available liquidity. 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 the DOE study. As of June 30, 2017, FES, its subsidiaries and FENOC had $174 million of net borrowings in the aggregate under the unregulated companies' money pool.

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 $295 million during the first six months of 2017 compared with $557 million provided from operating activities during the first six months of 2016. Cash flows from operations decreased $262 million in the first six months of 2017, compared with the same period of 2016 primarily due to lower collection of capacity revenues, as discussed above in "Results of Operations" and timing of working capital.

Cash Flows From Financing Activities

For the first six months of 2017, cash provided from financing activities was $7 million, compared to cash used for financing activities of $38 million in same period of 2016. The following table summarizes new debt financing (net of any discounts) and redemptions:

Securities Issued or Redeemed / Repaid	For the Six Months Ended June 30 2017	2016
	(In millions)	
Redemptions / Repayments		
PCRBs	$(158)	$(245)
Senior secured notes	(5)	—
	$(163)	$(245)
Short-term borrowings, net	$174	$210

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Cash Flows From Investing Activities

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

Cash Used for Investing Activities	For the Six Months Ended June 30 2017	2016
	(In millions)	
Property Additions	$169	$335
Nuclear fuel	134	188
Loans to affiliated companies, net	(29)	(11)
Investments	29	15
Other	(1)	(8)
	$302	$519

Cash used for investing activity for the first six months of 2017 decreased $217 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 June 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	$14	$—	$—	$—	$—	$33
Prices based on models	(2)	—	—	—	—	—	(2)
Total	$17	$14	$—	$—	$—	$—	$31

[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 June 30, 2017, an increase in commodity prices of 10% would decrease net income by approximately $15 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 FES' NDT are fixed income, equities and short-term investments carried at market values of approximately $993 million, $720 million and $83 million, respectively, as of June 30, 2017, excluding $(3) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $72 million reduction in fair value as of June 30, 2017. NG recognizes in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FES' NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

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 June 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 the 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 “Item 1A. Risk Factors” in the Registrants’ Annual Report on Form 10-K for the year ended December 31, 2016, which could materially affect the Registrants’ business, financial condition or future results. In addition, the information set forth in this report, including without limitation, the updated disclosures throughout and the supplemental risk factors presented below, updates and should be read in conjunction with, the risk factors and information disclosed in the Registrants’ documents previously filed with the SEC.

Risks Related to Our Transition to a Fully Regulated Utility and Risks Related to the CES Segment

Risks Related to Our Transition to a Fully Regulated Utility and Risks Related to the CES Segment Could Have an Adverse Effect on Us.

The reports we file with the SEC describe material risks that could adversely affect our business, cash flows, financial condition or results of operations, including risks related to our transition to a fully regulated utility and risks related to the CES segment. Further adverse developments in the CES segment, including at FES, could require FES to (i) restructure debt and other financial obligations or (ii) borrow additional funds from FE under its secured credit facility or the unregulated companies' money pool. In addition, FES, and likely FENOC, may determine to seek protection under U.S. bankruptcy laws regardless of the viability of one or more strategic alternatives. Any such developments could have important consequences, including:

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

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

Since beginning our strategic review of the CES segment, our competitive business has been pursuing the sale of certain generating and other assets. Because of the current financial condition of FES, those sales may be more difficult to execute at market values or at all. In January 2017, we announced that AES and AGC had entered into a purchase agreement to sell 1,572 MW of gas/hydro assets to a subsidiary of LS Power. The transaction is subject to various closing conditions, including receipt of regulatory approvals and the third party consents. The consent of VEPCO is needed for the sale of a portion 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. AE Supply and AGC and LS Power subsequently exercised a provision in the purchase agreement that allows either party to terminate the purchase agreement without penalty after June 23, 2017. The parties continue to negotiate with each other and with VEPCO and neither party has yet elected to exercise its termination rights. The parties are exploring alternative structures in terms of pricing and closing. In addition, as a result of the status of these ongoing negotiations regarding the asset purchase agreement and reflecting the impact of prevailing market conditions, CES recorded a non-cash pre-tax impairment charge of $131 million in the second quarter of 2017. If this sale or others by AE Supply or FES are not achieved or realized, AE Supply and FES may take further substantial write-downs and impairments of assets, which could have a material adverse effect on the results of operations and financial condition of FirstEnergy and FES and put additional pressure on the success of other strategic alternatives for remaining generation assets at our competitive business. There can be no assurance that the parties and/or VEPCO will come to an agreement, any required approvals will be obtained and/or all closing conditions will be satisfied or that such sale will be consummated.

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

FE has provided a revolving credit agreement to FES that permits borrowings of up to $500 million and provides additional credit support to FES of up to $200 million. As part of our centralized cash management functions, our unregulated companies, including FES, have the ability to borrow from each other and us to meet their short-term working capital requirements. At any time, FES and its subsidiaries also may be creditors to other of our unregulated companies or to us in amounts that may be material. In addition, FE has guaranteed certain material financial obligations of FES and its subsidiaries. We also could elect to assume or satisfy other material financial obligations of FES and its subsidiaries. It is also possible that creditors of FES may attempt to assert claims against us that may require significant effort and money to defend or could result in losses to us. Any of these matters could adversely affect our financial condition and cash flows and our ability to satisfy our obligations. In addition, the uncertainty associated with these matters could adversely affect our ability to access the capital or credit markets and our ability to finance our business.

Adverse Developments Related to our CES Segment Could Constitute Events of Default under Certain of Our Obligations.

FirstEnergy's credit facilities contain various events of default, including with respect to the borrowers or significant subsidiaries (each as defined in the credit agreements), a bankruptcy or insolvency, the failure to pay any principal of or premium or interest on any indebtedness in excess of $100 million, or the failure to satisfy any judgment or order for the payment of money exceeding any applicable insurance coverage by more than $100 million. Although FES and its subsidiaries are not "significant subsidiaries" for these purposes, it is possible that an adverse development related to FES could trigger an event of default under our credit facilities if creditors of FES asserted successful claims against us or our significant subsidiaries. Additionally, although the recent amendments to our credit facilities revised the debt to total capitalization ratio covenant to exclude non-cash charges of up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and their respective subsidiaries, charges beyond that amount could result in non-compliance with the debt-to-total-capitalization covenant resulting in an event of default related to our credit facilities. Any development, such as the bankruptcy or insolvency of our subsidiaries, debt acceleration or failures to satisfy judgments, could adversely affect our liquidity.

The Results of the Department of Energy Grid Study Could Affect the Value of Our CES Segment Assets.

On April 4, 2017, the Secretary of Energy directed the DOE to conduct a grid study to explore 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. At this time, we are uncertain as to when the DOE will publish the results of its ongoing grid study, as well as the potential impact that the report will have on FES and our strategic options, and the timing thereof, with respect to the competitive business.

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 second 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
April 1-30, 2017	—	—	—	—
May 1-31, 2017	1,883	$ 29.72	—	—
June 1-30, 2017	—	—	—	—
Second Quarter	1,883	$ 29.72	—	—

(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) 3.1	Amended Articles of Incorporation of FirstEnergy Corp., as amended July 25, 2017
4.1	Officer’s Certificate relating to FirstEnergy Corp.’s 2.85% Notes, Series A, due 2022, 3.90% Notes, Series B, due 2027 and 4.85% Notes, Series C, due 2047 (incorporated by reference to FirstEnergy Corp.’s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
4.2	Form of 2.85% Note, Series A, due 2022 (incorporated by reference to FirstEnergy Corp.’s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
4.3	Form of 3.90% Note, Series B, due 2027 (incorporated by reference to FirstEnergy Corp.’s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
4.4	Form of 4.85% Note, Series C, due 2047 (incorporated by reference to FirstEnergy Corp.’s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
(A) 10.1	Guarantee, dated as of February 21, 2017, by FirstEnergy Corp. in favor of participants under the FirstEnergy Corp. Cash Balance Pension Restoration Plan
(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 June 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) 10.1	Settlement Agreement, dated May 1, 2017, by and among FirstEnergy Corp. and FirstEnergy Generation, LLC and BNSF Railway Company and CSX Transportation, Inc.
(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 June 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.

July 27, 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)

EXHIBIT INDEX

Exhibit Number	
FirstEnergy	
(A) 3.1	Amended Articles of Incorporation of FirstEnergy Corp., as amended July 25, 2017
4.1	Officer's Certificate relating to FirstEnergy Corp.'s 2.85% Notes, Series A, due 2022, 3.90% Notes, Series B, due 2027 and 4.85% Notes, Series C, due 2047 (incorporated by reference to FirstEnergy Corp.'s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
4.2	Form of 2.85% Note, Series A, due 2022 (incorporated by reference to FirstEnergy Corp.'s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
4.3	Form of 3.90% Note, Series B, due 2027 (incorporated by reference to FirstEnergy Corp.'s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
4.4	Form of 4.85% Note, Series C, due 2047 (incorporated by reference to FirstEnergy Corp.'s Form 8-K filed June 21, 2017, Exhibit 4.1, File No. 333-21011)
(A) 10.1	Guarantee, dated as of February 21, 2017, by FirstEnergy Corp. in favor of participants under the FirstEnergy Corp. Cash Balance Pension Restoration Plan
(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 June 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) 10.1	Settlement Agreement, dated May 1, 2017, by and among FirstEnergy Corp. and FirstEnergy Generation, LLC and BNSF Railway Company and CSX Transportation, Inc.
(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 June 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.