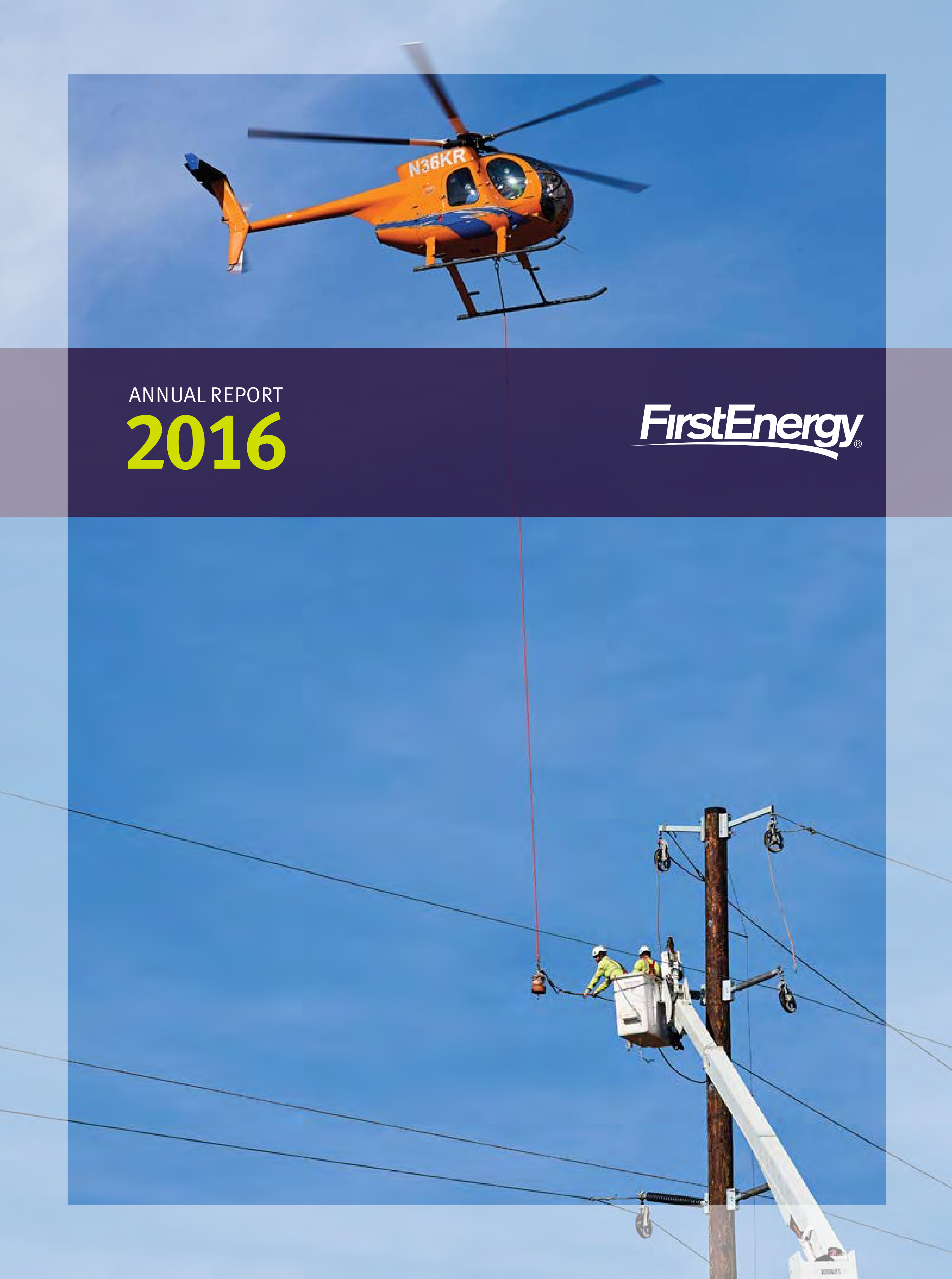
ANNUAL REPORT

2016

FirstEnergy



FINANCIAL HIGHLIGHTS

2016 KEY ACCOMPLISHMENTS

- Generated $3.4 billion in cash from operations
- Maintained dividend of $1.44 per share
- Attained top-decile safety performance in our industry by achieving the best safety record in our company's history
- Invested $1 billion to modernize our transmission system as part of our *Energizing the Future* initiative
- Installed nearly 550,000 smart meters in Pennsylvania
- Deployed advanced technologies to enhance transmission system reliability

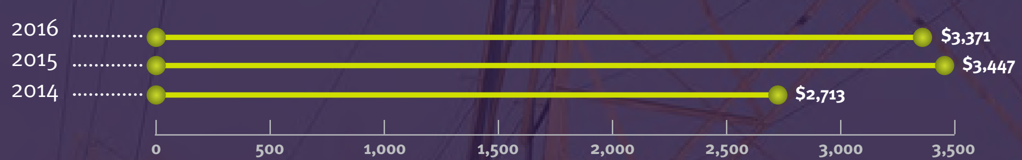
FINANCIALS AT A GLANCE

(dollars in millions, except per share amounts)

	2016	2015	2014
TOTAL REVENUES	$14,562	$15,026	$15,049
NET INCOME (LOSS)	$(6,177)	$578	$299
BASIC AND DILUTED EARNINGS per common share	$(14.49)	$1.37	$0.71
DIVIDENDS PAID per common share	$1.44	$1.44	$1.44
BOOK VALUE per common share	$14.11	$29.33	$29.49

NET CASH FROM OPERATING ACTIVITIES

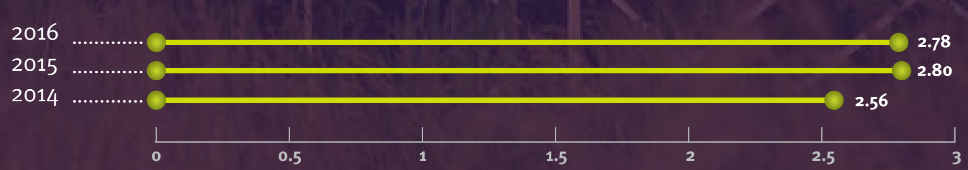
(in millions)



REGULATED TRANSMISSION AND DISTRIBUTION REVENUES

(in millions)

TRANSMISSION AND DISTRIBUTION RELIABILITY INDEX*



*FirstEnergy's index comprises two indices that are commonly used in the electric utility industry: Transmission Outage Frequency (TOF) and System Average Interruption Duration Index (SAIDI). Our index measures frequency and duration of service interruptions: the better the performance, the higher the score.

A MESSAGE TO OUR SHAREHOLDERS

In 2016, we continued to make solid progress in pursuing a regulated growth strategy that will help us better serve our customers, communities and the environment.

We strengthened our energy infrastructure through significant investments designed to enhance service reliability for customers and improve operating efficiencies. These investments build on the scale and diversity of our regulated operations, with the goal of achieving more sustainable and customer-focused growth over the long term.

We're also addressing the significant challenges facing our competitive generation business, including weak power prices, insufficient capacity markets and sluggish demand for electricity in our region. During the year, we continued taking aggressive steps to cut costs and advocate for energy market reforms that could support our critical baseload generating plants.

TRANSITIONING TO A REGULATED COMPANY

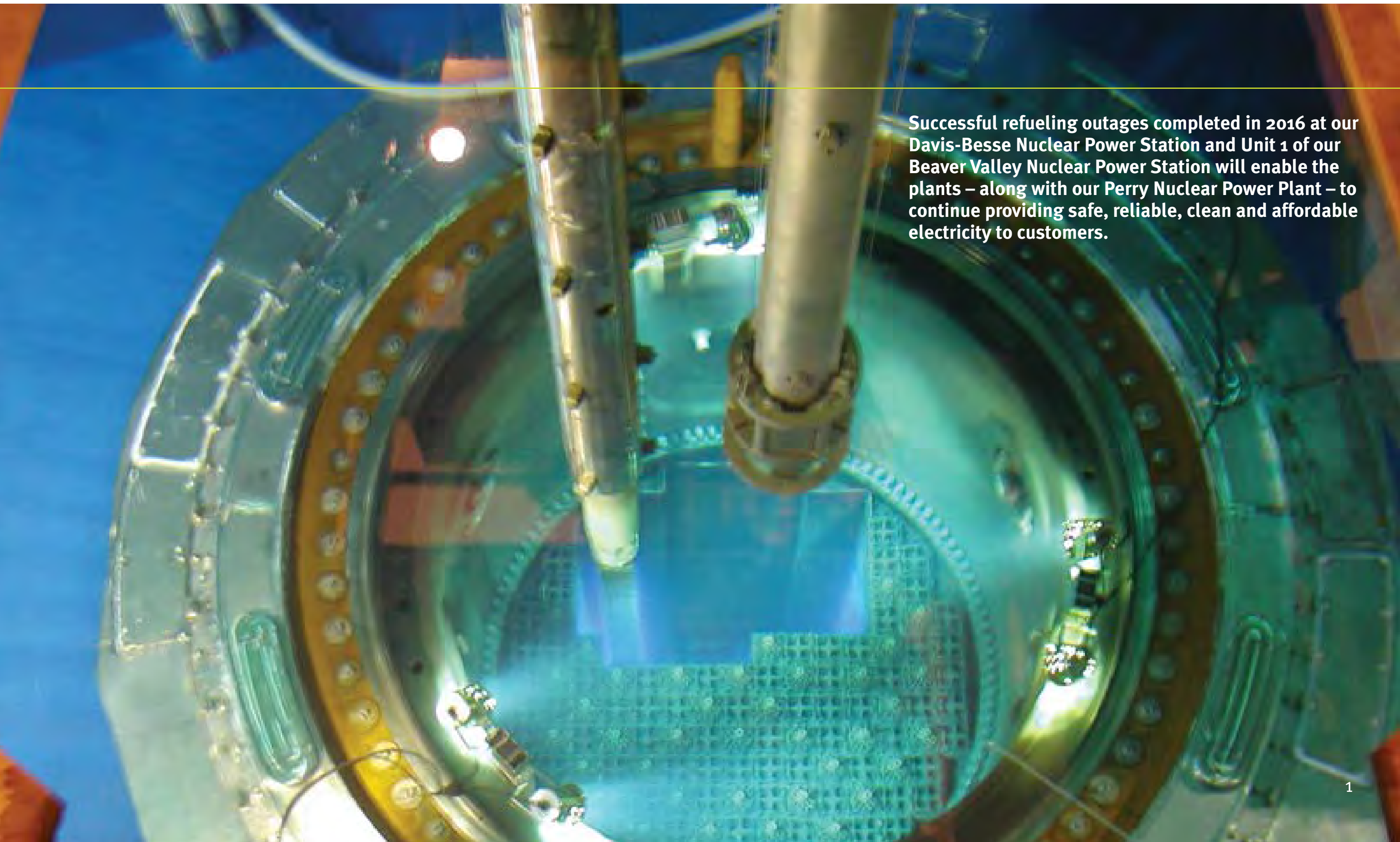
As competitive energy markets continued to devalue baseload coal and nuclear generation, we announced our intention to exit these markets and transition to a fully regulated company. Recognizing that our investors and employees need closure, we're pursuing an accelerated time frame and are targeting to implement this exit by mid-2018.

Charles E. Jones
President and
Chief Executive Officer

Consistent with this strategy, we entered into an agreement to sell four competitive natural gas power plants in Pennsylvania and the competitive portion of a Virginia hydroelectric power station. Under the terms of the agreement, the five facilities – Springdale Generating Facility Units 1-5, Chambersburg Generating Facility Units 12-13, Gans Generating Facility Units 8-9, Hunlock Creek and the competitive share of Bath County Hydro – would be purchased for $925 million in an all-cash transaction with net proceeds exceeding $300 million after we repay debt. The transaction is expected to close in the third quarter of this year, subject to a number of regulatory approvals and consents from third parties.

In the fourth quarter of 2016, we recorded a non-cash, pre-tax impairment charge of $9.2 billion to reduce the carrying value of certain assets – including generating plants, nuclear fuel and related materials and supplies – to their estimated fair value. This decision is based on a recognition that, given our timetable to exit competitive markets and the anticipated cash flows over this period, the carrying value of these long-standing assets is not recoverable.

We're also taking steps to convert competitive generation to a regulated or regulated-like construct. In March of this year, our Mon Power and Potomac Edison utilities filed a plan



Successful refueling outages completed in 2016 at our Davis-Besse Nuclear Power Station and Unit 1 of our Beaver Valley Nuclear Power Station will enable the plants – along with our Perry Nuclear Power Plant – to continue providing safe, reliable, clean and affordable electricity to customers.

seeking regulatory approval to acquire the competitive Pleasants Power Station as the least-cost source to meet a capacity shortfall in their West Virginia service areas. In addition, we're participating in legislative efforts in Ohio and Pennsylvania that recognize the environmental and energy security benefits of our baseload nuclear plants.

In response to challenging market conditions, we're making operational changes at two of our Ohio power plants. In 2016, we announced the planned retirement of Units 1 through 4 – a total capacity of 720 megawatts (MW) – at our seven-unit W.H. Sammis Plant in Stratton, Ohio. We also plan to sell or deactivate the 136-MW Unit 1 at our Bay Shore Plant in Oregon, Ohio. Although employees at both facilities have worked hard to make these plants more productive and efficient, we simply cannot continue to operate these units in the current pricing environment.

These and other significant changes demand that we take a critical look at how our company can deliver greater value to customers and shareholders in the years ahead. Toward that end, a team of employees is evaluating our organization to identify and understand how shared services – such as legal, accounting, communications and human resources – will be allocated across the enterprise and ensure we have the right structure in place to support our efforts to become a fully regulated utility.

As your company moves away from competitive generation, we're also committed to making the appropriate investments to ensure the safe and reliable operation of our generating fleet. And we remain dedicated to achieving excellence in all aspects of our nuclear performance – from the fundamentals of safe plant operations to the successful execution of refueling outages.

INVESTING IN OUR CUSTOMERS

Despite the challenges facing our competitive subsidiaries, FirstEnergy's 10 electric utility operating companies remain strong. Our utilities provide stable, predictable cash flows and earnings.

We continue to build on this strength by implementing our *Energizing the Future* transmission investment program – an essential part of our efforts to ensure customers benefit from a more reliable grid in the years ahead.

With phase one of the program nearly completed, we expect to spend an additional $4.2 billion to $5.8 billion from 2017 to 2021 as we extend it across our entire transmission system. Projects funded through the program are designed to help us meet the evolving energy needs of our customers and ensure long-term service reliability; add resiliency to our transmission system; meet expected load growth from shale gas activity in our service area; and increase physical and cyber security.

To better support these efforts, we created a new transmission affiliate, Mid-Atlantic Interstate Transmission (MAIT), and filed for implementation of forward-looking formula rates. These actions will help us more effectively finance and build transmission facilities within our Met-Ed and Penelec service areas.

In New Jersey, we completed an 11.5-mile transmission line in Mercer, Middlesex and Monmouth counties, which benefits nearly 34,000 customers of Jersey Central Power & Light (JCP&L). Also, construction is now underway for a new transmission substation near Burgettstown, Pa., that will reinforce the regional transmission system and support the area's expanding Marcellus shale gas industry while benefiting more than 40,000 customers of West Penn Power.

6M
CUSTOMERS
IN THE MIDWEST AND MID-ATLANTIC REGIONS

65K
SQUARE MILES
OF SERVICE TERRITORY

273K
MILES
OF DISTRIBUTION LINES

Shale gas development also is being supported by two projects in West Virginia: the 18-mile Oak Mound-Waldo Run transmission line and the Richwood Hill Transmission Project, which includes equipment that helps regulate voltage, a switching station and a 2.2-mile transmission line. Both projects also will help enhance service reliability for thousands of Mon Power customers.

We're making steady progress with our Pennsylvania smart meter program, with nearly 550,000 smart meters installed across our four utility operating companies in the state last year. We plan to deploy smart meters to nearly all of our 2 million Pennsylvania customers by mid-2019.

We reached a key milestone in August when we began deploying automated meter reading and billing functionality for Penn Power customers. This marks a significant step toward providing customers with more detailed information on their energy use and helping them make better-informed energy decisions. Met-Ed, Penelec and West Penn Power customers with smart meters will transition to automated billing in 2017.

In Ohio, we will work closely with the Public Utilities Commission of Ohio (PUCO) on a Grid Modernization Plan that could include smart meters and other technologies.

RECOVERING COSTS OF SERVING CUSTOMERS

Favorable rulings on several regulatory initiatives will help ensure the appropriate and timely recovery of investments in our distribution system.

In January of this year, the Pennsylvania Public Utility Commission approved a base rate case settlement that will help support and build on the significant service reliability enhancements made in recent years to benefit customers of Met-Ed, Penelec, Penn Power and West Penn Power. The ruling will result in approximately $290 million in incremental annual revenue for those utilities.

In Ohio, the PUCO approved modifications to our comprehensive Electric Security Plan IV (ESP). The plan's Ohio Distribution Modernization Rider enables Toledo Edison, Ohio Edison and The Illuminating Company to collect $204 million annually (grossed up for taxes) through 2019, with a possible two-year extension. The resulting revenue could be used to support major upgrades to our electric system in Ohio. Potential service reliability projects could include the rehabilitation of urban-area network systems, replacement of underground cable, overhead and substation circuit upgrades, integration of smart grid technologies and evaluation of battery technology.

In New Jersey, the Board of Public Utilities (BPU) issued an order adopting a JCP&L rate settlement that increases revenue $80 million annually and approved the accelerated recovery of our deferred storm-related costs in the state. The decision reflects JCP&L's recent efforts to enhance service reliability and relationships with key constituencies in New Jersey.

In West Virginia, the state's Public Service Commission approved a settlement agreement with our Mon Power and Potomac Edison utilities allowing recovery of costs for fuel, purchased power expenses, energy efficiency programs and environmental controls incurred by the utilities to provide safe, reliable and clean electricity to customers.

PURSUING REVENUE GROWTH OPPORTUNITIES

To support long-term growth, we're developing a wide range of customer-focused initiatives that also would serve as alternative sources of revenue for your company.

Established in 2015, our FE Products Group expanded its portfolio of offerings designed to provide greater value to customers. While continuing to market existing products such as surge assistance and protection, electrical services and security lighting, the group introduced plumbing repair plans and smart thermostats. We're also exploring the development of less-traditional products and services designed to enhance our customers' quality of life.

In addition, we created an electrification initiative that connects commercial and industrial customers with new, energy-efficient equipment and other products. These include electric forklifts and heating products designed to improve our business customers' productivity and efficiency while enhancing their competitiveness and sustainability efforts.

We're well-positioned to bring new products and services to market. Our utility companies share strong brand name recognition and a long-standing community presence, and customers view our utilities as trusted sources for energy-saving programs and tips. Industry studies have shown that customers are receptive to buying value-added products and services from

their electric companies, and that these offerings help increase customer satisfaction.

We look forward to developing additional products and services that can help grow our business while bringing greater comfort, convenience, security and productivity to our residential and business customers.

WORKING SAFELY

In 2016, we attained top-decile safety performance in our industry with a companywide OSHA-recordable injury rate of 0.59 – less than one injury per 200,000 hours worked.

Employees at several locations across our service area achieved safety milestones, including those working at our Perry Warehouse in Ohio and our Harrisville Service Center in West Virginia, who celebrated working safely for 22 and 29 years, respectively, without OSHA-recordable injuries.

Met-Ed and West Penn Power were honored with the prestigious Governor's Award for Safety Excellence (GASE) from the Pennsylvania Department of Labor and Industry. GASE recognizes companies that have achieved the highest standards in workplace safety by establishing successful employer-employee joint safety programs. Also, our Fort Martin Power Station in Maidsville, W.Va., earned its fourth-consecutive OSHA Voluntary Protection Program Star status for its strong commitment to safe work practices.

Our outstanding safety performance reflects the great importance we place on ensuring our working men and women have the tools, information and processes necessary to perform their duties safely. We will continue to strive every day to strengthen our safety culture and promote an incident-free workplace.

OUR MISSION

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

SUSTAINING OUR CUSTOMERS AND COMMUNITIES

FirstEnergy's sustainability efforts encompass virtually every facet of our business and reflect our ongoing commitment to protect the environment and create lasting value in the communities where we live and work.

First and foremost, we work to minimize the environmental impact of our generating plants and other facilities. For example, our generating fleet has adopted human performance practices to lessen the impact of these facilities on our communities and the environment. In addition, our Mon Power and Potomac Edison utilities are investing in emission control technologies that enable the regulated Harrison and Fort Martin power stations to meet increasingly stringent environmental standards.

Our utility customers benefit from a wide range of energy efficiency programs designed to help them better manage their energy use. Residential and low-income programs include incentives for energy-efficient home construction; rebates on the purchase of energy-efficient products; home energy usage reports and audits; and home energy efficiency kits and education. Commercial and industrial programs include incentives for installing energy-efficient lighting, motors, drives and other energy-efficient equipment and processes; energy audits and technology assessments; and HVAC efficiency incentives.

Our sustainability efforts also focus on economic development and community support. Over the past 10 years, we helped attract nearly $27 billion in capital investment and create more than 75,000 jobs in our service area. Moreover, since 2001, our companies and the FirstEnergy Foundation have provided more than $68 million in contributions and grants to nearly 2,900 community-based organizations and charities, many of which also benefit from the volunteer efforts of our employees. Among other priorities, the FirstEnergy Foundation promotes a highly diverse and educated workforce by supporting professional development, literacy, and science, technology, engineering and mathematics (STEM) education initiatives in our communities.

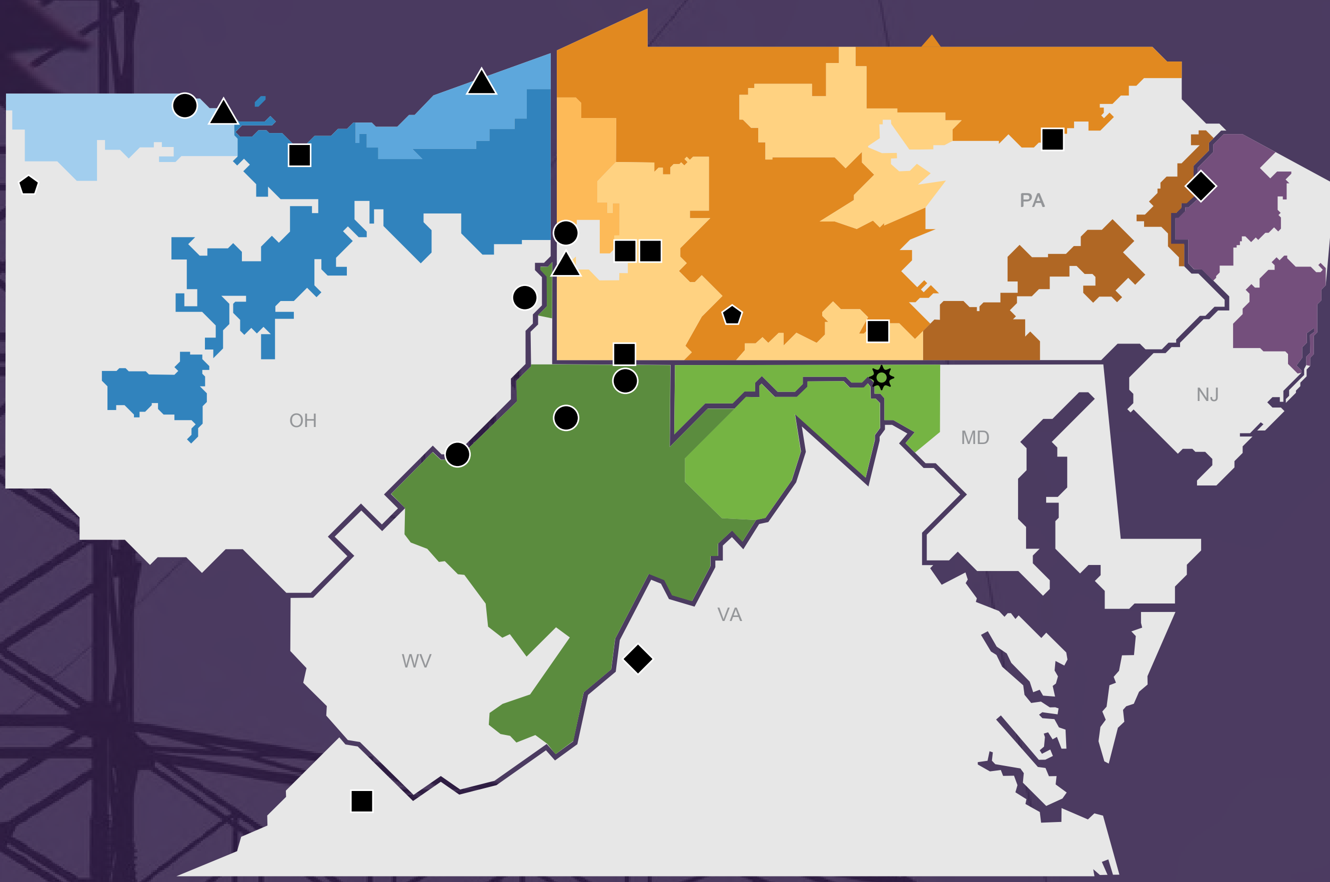
BUILDING A STRONGER FIRSTENERGY

Although the steps we took in 2016 have created greater opportunities for your company's future success, we will continue to need the best efforts of our employees to meet the significant challenges that lie ahead.

I believe we're on the right path to create a fully regulated company, with a stronger focus on meeting the energy needs of the 6 million utility customers we're privileged to serve. Our diverse, high-performing team is dedicated to providing those customers with the safe, reliable, clean and affordable electricity they expect and deserve.

I thank you for your support of FirstEnergy, and I'm confident our employees are up to the challenge of unlocking the full value of your investment in our company.

Charles E. Jones
President and Chief Executive Officer
March 15, 2017



CORPORATE PROFILE

Headquartered in Akron, Ohio, FirstEnergy is a leading regional energy provider dedicated to safety, operational excellence and responsive customer service. Our subsidiaries are involved in the transmission, distribution and generation of electricity.

Our 10 utility operating companies form one of the nation's largest investor-owned electric systems based on 6 million customers served within a nearly 65,000-square-mile area of Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York. The company's transmission subsidiaries operate approximately 24,500 miles of transmission lines connecting the Midwest and Mid-Atlantic regions.

FirstEnergy subsidiaries own or control generating capacity from nuclear, coal, natural gas, hydro, wind and solar facilities.

FirstEnergy Solutions, our competitive subsidiary, is a retail energy supplier serving residential, commercial and industrial customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan and Illinois.

Ohio
- Ohio Edison
- The Illuminating Company
- Toledo Edison

Pennsylvania
- Met-Ed
- Penelec
- Penn Power
- West Penn Power

West Virginia/Maryland
- Mon Power
- Potomac Edison

New Jersey
- Jersey Central Power & Light

Generating Stations
- ● Coal
- ■ Gas/Oil
- ◆ Hydro
- ▲ Nuclear
- ⬟ Wind
- ✲ Solar

DEAR SHAREHOLDERS:

During 2016, your management team focused on building a stronger FirstEnergy by making significant investments in its regulated utility operations and launching a strategic review targeting an exit from competitive generation by mid-2018.

Your Board provided an annual dividend rate of $1.44 per share in 2016. We will continue to review the dividend on a quarterly basis as FirstEnergy addresses the opportunities and challenges that lie ahead.

On a personal note, let me express my gratitude to Robert (Yank) B. Heisler Jr., Ted J. Kleisner and Ernest J. Novak Jr., who will no longer be members of the Board after the 2017 Annual Meeting of Shareholders. The Board is sincerely thankful for the leadership and guidance Yank, Ted and Ernie provided during their many years of distinguished service to FirstEnergy and its shareholders.

I welcome Steven J. Demetriou and James F. O'Neil III, who were elected to the Board in January 2017. Steve and Jim are well-respected and seasoned leaders who bring extensive executive and board experience to our company and its shareholders. Steve is chairman and chief executive officer of Jacobs Engineering Group, Inc. Prior to joining Jacobs in 2015, he served as chairman and chief executive officer of Aleris Corporation. Jim is a partner at Western Commerce Group, an advisory and investment firm, and was formerly president, chief executive officer and a director of Quanta Services, Inc.

Your Board remains committed to ensuring your interests are well represented as we work with management to enhance the value of your investment in FirstEnergy. Thank you for your continued support.

Sincerely,

George M Smart

George M. Smart
Chairman of the Board

FIRSTENERGY EXECUTIVE OFFICERS*

Charles E. Jones
President and Chief Executive Officer

Leila L. Vespoli
Executive Vice President, Corporate Strategy, Regulatory Affairs and Chief Legal Officer

James H. Lash
Executive Vice President and President, FE Generation

James F. Pearson
Executive Vice President and Chief Financial Officer

Gary D. Benz
Senior Vice President, Strategy

Lynn M. Cavalier
Chief Human Resource Officer

Dennis M. Chack
Senior Vice President, Marketing and Branding

Michael J. Dowling
Senior Vice President, External Affairs

Bennett L. Gaines
Senior Vice President, Corporate Services and Chief Information Officer

Charles D. Lasky
Senior Vice President, Human Resources

Robert P. Reffner
Vice President and General Counsel

Donald R. Schneider
President, FirstEnergy Solutions

Steven E. Strah
Senior Vice President and President, FirstEnergy Utilities

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

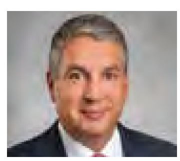
*More detailed information on the principal occupation or employment of each of our executive officers and the principal business of any organization by which FirstEnergy Executive Officers are employed may be found on page 164 of this report.

FIRSTENERGY BOARD OF DIRECTORS

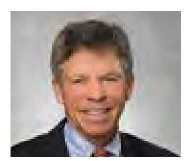
Paul T. Addison
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (CitiGroup).

Michael J. Anderson
Chairman of the Board of The Andersons, Inc. (diversified agribusiness).

William T. Cottle
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company.

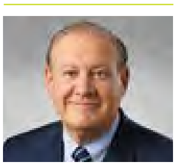


Steven J. Demetriou
Chairman and Chief Executive Officer of Jacobs Engineering Group, Inc. (technical professional and construction services firm).

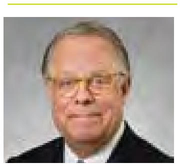


Robert B. Heisler Jr.
Retired, formerly Dean of the College of Business Administration and Graduate School of Management of Kent State University. Retired Chairman of the Board of KeyBank N.A.

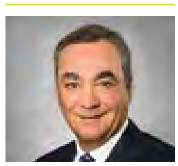
Julia L. Johnson
President of NetCommunications, LLC (regulatory and public affairs firm).



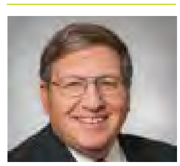
Charles E. Jones
President and Chief Executive Officer of FirstEnergy Corp.



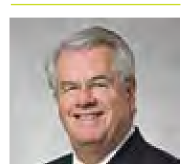
Ted J. Kleisner
Retired, formerly Chairman of the Board and Chief Executive Officer of Hershey Entertainment & Resorts Company.



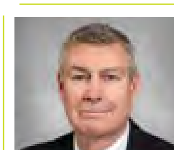
Donald T. Misheff
Retired, formerly Managing Partner of the Northeast Ohio offices of Ernst & Young LLP.



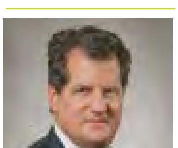
Thomas N. Mitchell
Retired, formerly President, Chief Executive Officer and Director of Ontario Power Generation Inc.



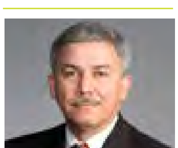
Ernest J. Novak Jr.
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP.



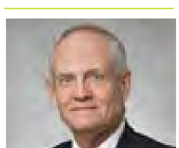
James F. O'Neil III
Partner, Western Commerce Group (advisory and investment firm).



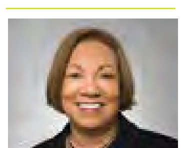
Christopher D. Pappas
President, Chief Executive Officer and Director of Trinseo S.A. (plastics, latex and rubber producer).



Luis A. Reyes
Retired, formerly Regional Administrator of the U.S. Nuclear Regulatory Commission.



George M. Smart
Non-executive Chairman of the FirstEnergy Corp. Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc.



Dr. Jerry Sue Thornton
Chief Executive Officer of Dream Catcher Educational Consulting (higher education coaching and professional development). Retired President of Cuyahoga Community College.

ANNUAL REPORT

2016

CONTENTS

GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, which provided legal, financial and other corporate support services to the former AE subsidiaries
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
Buchanan Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply
Buchanan Generation	Buchanan Generation, LLC, a joint venture between AE Supply and CNX Gas Corporation
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FELHC, Inc.
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., together with its consolidated subsidiaries, which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, which is the parent of ATSI, MAIT and TrAIL and has a joint venture in PATH
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly-owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FGMUC	FirstEnergy Generation Mansfield Unit 1 Corp., a wholly-owned subsidiary of FG, which owns various leasehold interests in Bruce Mansfield Unit 1
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	Global Rail Group, LLC, a subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FE on November 7, 2001
Green Valley	Green Valley Hydro, LLC, which owned hydroelectric generating stations
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate 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
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
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
AMT	Alternative Minimum Tax
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
Aspen	Aspen Generating, LLC, a wholly-owned subsidiary of LS Power Equity Partners III, LP
ASU	Accounting Standards Update
Bath County	Bath County Pumped Storage Hydro-Power Station
BGS	Basic Generation Service
bps	Basis points
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CBA	Collective Bargaining Agreement
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFL	Compact Fluorescent Light
CFR	Code of Federal Regulations
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CONE	Cost-of-New-Entry
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCPD	Deferred Compensation Plan for Outside Directors
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
DTA	Deferred Tax Asset
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EGU	Electric Generation Unit
ELPC	Environmental Law & Policy Center
EMAAC	Eastern Mid-Atlantic Area Council of PJM
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency

EPRI	Electric Power Research Institute
ERISA	Employee Retirement Income Security Act of 1974
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
ESP IV	Electric Security Plan IV
ESP IV PPA	Unit Power Agreement entered into on April 1, 2016 by and between the Ohio Companies and FES
ESTIP	Executive Short-Term Incentive Program
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
HCl	Hydrochloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICP 2007	FirstEnergy Corp. 2007 Incentive Plan
ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour
KPI	Key Performance Indicator
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LED	Light Emitting Diode
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Price
LOC	Letter of Credit
LSE	Load Serving Entity
LTIIPs	Long-Term Infrastructure Improvement Plans
MAAC	Mid-Atlantic Area Council of PJM
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.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
Ninth Circuit	United States Court of Appeals for the Ninth Circuit

NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOAC	Northwest Ohio Aggregation Coalition
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
OPEB	Other Post-Employment Benefits
OPEIU	Office and Professional Employees International Union
ORC	Ohio Revised Code
OTC	Over The Counter
OTTI	Other-Than-Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Purchase Power Agreement
PPB	Parts per Billion
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PTC	Price-to-Compare
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
Regulation FD	Regulation Fair Disclosure promulgated by the SEC
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
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
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB221	Amended Substitute Senate Bill No. 221
SB310	Substitute Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SRC	Storm Recovery Charge
SREC	Solar Renewable Energy Credit
SSA	Social Security Administration
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
TTS	Temporary Transaction Surcharge
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
UWUA	Utility Workers Union of America
VEPCO	Virginia Electric Power Company
VIE	Variable Interest Entity
VRR	Variable Resource Requirement
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

ITEM 6. SELECTED FINANCIAL DATA

FirstEnergy

For the Years Ended December 31,	2016	2015	2014	2013	2012
	(In millions, except per share amounts)				
Revenues	$ 14,562	$ 15,026	$ 15,049	$ 14,892	$ 15,255
Income (Loss) From Continuing Operations	$ (6,177)	$ 578	$ 213	$ 375	$ 755
Earnings (Loss) Available to FirstEnergy Corp.	$ (6,177)	$ 578	$ 299	$ 392	$ 770
Earnings (Loss) per Share of Common Stock:					
Basic - Continuing Operations	$ (14.49)	$ 1.37	$ 0.51	$ 0.90	$ 1.81
Basic - Discontinued Operations (Note 20)	—	—	0.20	0.04	0.04
Basic - Earnings (Loss) Available to FirstEnergy Corp.	$ (14.49)	$ 1.37	$ 0.71	$ 0.94	$ 1.85
Diluted - Continuing Operations	$ (14.49)	$ 1.37	$ 0.51	$ 0.90	$ 1.80
Diluted - Discontinued Operations (Note 20)	—	—	0.20	0.04	0.04
Diluted - Earnings (Loss) Available to FirstEnergy Corp.	$ (14.49)	$ 1.37	$ 0.71	$ 0.94	$ 1.84
Weighted Average Shares Outstanding:					
Basic	426	422	420	418	418
Diluted	426	424	421	419	419
Dividends Declared per Share of Common Stock	$ 1.44	$ 1.44	$ 1.44	$ 1.65	$ 2.20
Total Assets[1]	$ 43,148	$ 52,094	$ 51,552	$ 49,980	$ 50,110
Capitalization as of December 31:					
Total Equity	$ 6,241	$ 12,422	$ 12,422	$ 12,695	$ 13,093
Long-Term Debt and Other Long-Term Obligations	18,192	19,099	19,080	15,753	15,114
Total Capitalization	$ 24,433	$ 31,521	$ 31,502	$ 28,448	$ 28,207

[1]Reflects the retrospective application of ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs, which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The retrospective change decreased Total Assets as of December 31 as follows: 2015 - $93 million, 2014 - $96 million, 2013 - $78 million, 2012 - $65 million, as these amounts were reclassified from deferred charges and other assets to long-term debt and other long-term obligations.

PRICE RANGE OF COMMON STOCK

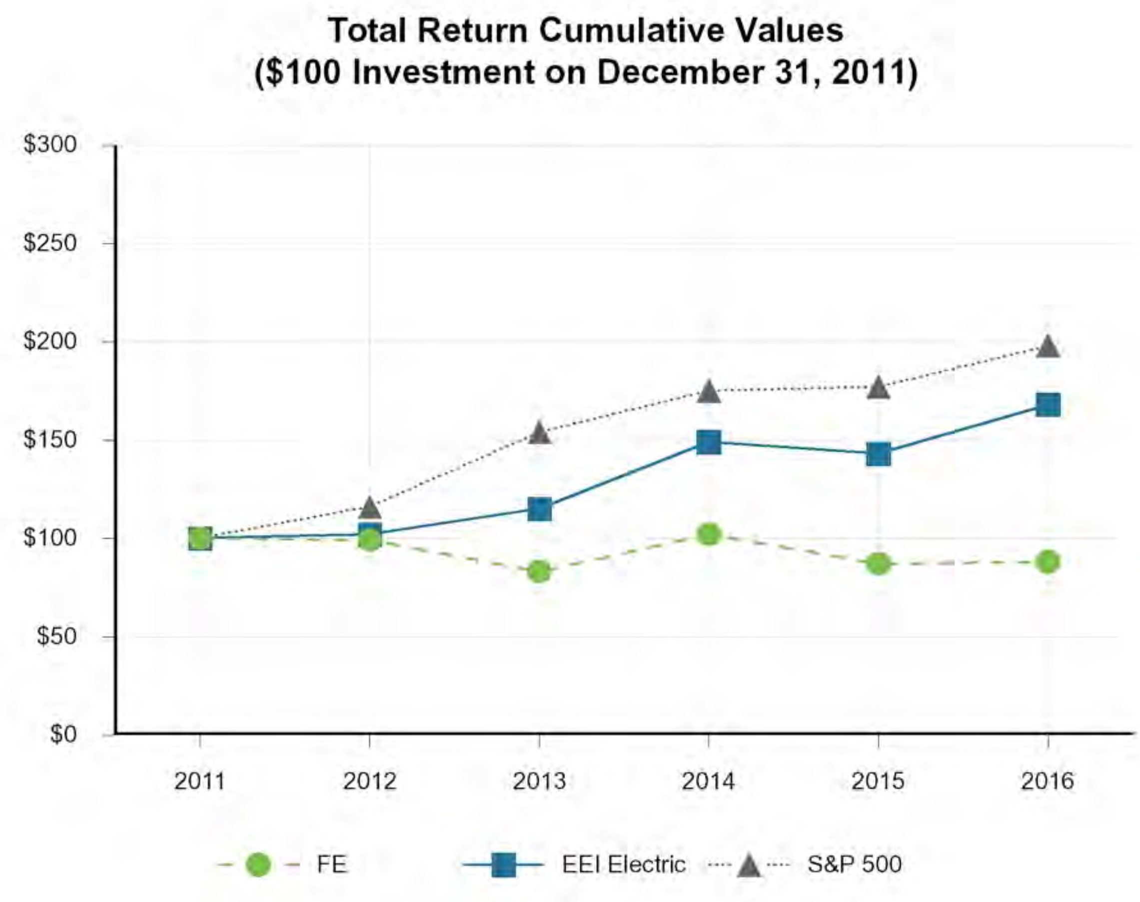
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2016		2015	
	High	Low	High	Low
First Quarter	$ 36.54	$ 30.62	$ 41.68	$ 33.82
Second Quarter	$ 36.32	$ 31.37	$ 37.05	$ 32.46
Third Quarter	$ 36.60	$ 32.12	$ 35.09	$ 30.31
Fourth Quarter	$ 34.83	$ 29.33	$ 33.00	$ 28.89
Yearly	$ 36.60	$ 29.33	$ 41.68	$ 28.89

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

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2011 in FE's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 85,173 and 85,172 holders of 442,344,218 and 442,477,633 shares of FE's common stock as of December 31, 2016 and January 31, 2017, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12, Capitalization of the Combined Notes to Consolidated Financial Statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. 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.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including, but not limited to, our planned forward-looking formula rates and the effectiveness of our strategy to reflect a more regulated business profile.
- 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 through, among other actions, our cash flow improvement plan and other proposed capital raising initiatives.
- The risks and uncertainties associated with the lack of viable alternative strategies regarding the CES segment, thereby causing FES, and possibly 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 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 possibly 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 speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- 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 and the Ohio DMR.
- 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, and revised 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 the subsidiaries within the CES segment.
- 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 (a) Item 1A. Risk Factors to FirstEnergy's Form 10-K for the fiscal year ended December 31, 2016, (b) this Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in other filings with the SEC by the registrants. 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.

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.

During the fourth quarter of 2016, FirstEnergy modified its segment reporting to reclassify the results of operations from certain transmission assets of ME, PN and JCP&L, from the Regulated Distribution segment to the Regulated Transmission segment. Costs associated with these transmission assets, which are currently included in ME, PN, and JCP&L's stated rates, will be recovered through MAIT's and JCP&L’s formula rates prospectively, once approved by FERC. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2015 and 2014 have been revised to conform to the current presentation reflecting the operating activity of the identified transmission assets within Regulated Transmission.

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

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

Company	Area Served	Customers Served [(1)]
OE	Central and Northeastern Ohio	1,045
Penn	Western Pennsylvania	165
CEI	Northeastern Ohio	750
TE	Northwestern Ohio	310
JCP&L	Northern, Western and East Central New Jersey	1,117
ME	Eastern Pennsylvania	565
PN	Western Pennsylvania	588
WP	Southwest, South Central and Northern Pennsylvania	724
MP	Northern, Central and Southeastern West Virginia	390
PE	Western Maryland and Eastern West Virginia	404
		6,058

(1) As of December 31, 2016

The **Regulated Transmission** segment transmits electricity through transmission facilities owned and operated by ATSI and TrAIL and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project. 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 "FERC Matters" below, effective January 31, 2017, MAIT includes the transmission assets of ME and PN, and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. Those applications are pending before FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under the forward-looking rates, each of ATSI's and TrAIL's 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. Except for the recovery of the PATH abandoned project regulatory asset, the segment's revenues are primarily from transmission services provided to LSEs pursuant to the PJM Tariff. 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 December 31, 2016, 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 Aspen and the 1,300 MW Pleasants power station which was offered into MP's RFP process by AE Supply. 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 December 31, 2016, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $2.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

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

Over the past several years, CES has been impacted by a 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. 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 prices from the 2019/2020 PJM Base Residual Auction in May of 2016 as well as the current forward pricing and the long-term fundamental view on energy and capacity prices, which resulted in a non-cash pre-tax impairment charge of $800 million ($23 million at FES) recognized in the second quarter of 2016 representing the total amount of goodwill at CES.

As part of a continual process to evaluate its overall generation business, on July 22, 2016, FirstEnergy announced its intent to exit the 136 MW Bay Shore Unit 1 generating station by October 2020 and to deactivate Units 1-4 of the W.H. Sammis generating station totaling 720 MWs by May 2020, resulting in a $647 million ($517 million at FES) non-cash pre-tax impairment charge in the second quarter of 2016. Furthermore, in November of 2016, FirstEnergy announced that it had begun a strategic review of its competitive operations as it transitions to a fully regulated utility 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 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 Bath County (1,572 MWs of combined capacity) for an all cash purchase price of $925 million, subject to customary and other closing conditions as further discussed below under "Competitive Generation Asset Sale", including 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. Additionally, in connection with MP's RFP seeking additional generation capacity, AE Supply offered the Pleasants power station (1,300 MWs) for approximately $195 million. A winning bidder is expected to be announced in connection with the filing of appropriate applications for approval of the transactions with the WVPSC and FERC.

Although FirstEnergy is targeting mid-2018 to exit from competitive operations, the options for the remaining portion of CES' generation 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,
- Additional asset sales and/or plant deactivations,
- Restructuring FES debt with its creditors, and/or
- Seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

Furthermore, adverse outcomes in previously disclosed disputes regarding long-term coal transportation contracts and/or the inability to extend or refinance debt maturities at FES subsidiaries, could accelerate management's targeted timeline and limit its options to exit competitive operations to either restructuring debt with its creditors or seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

As part of assessing the viability of strategic alternatives, FirstEnergy determined that the carrying value of long-lived assets of the competitive business were not recoverable, specifically given FirstEnergy's target to implement its exit from competitive operations by mid-2018, significantly before the end of their original useful lives, and the anticipated cash flows over this shortened period. As a result, CES recorded a non-cash pre-tax impairment charge of $9,218 million ($8,082 million at FES) in the fourth quarter of 2016 to reduce the carrying value of certain assets to their estimated fair value, including long-lived assets such as generating plants and nuclear fuel, as well as other assets such as materials and supplies.

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 sale of the AE Supply natural gas generating plants and AGC's interest in Bath County and, if accepted in the MP RFP process as the winning bidder, the transfer of the Pleasants Power station to MP, the size and generation capacity of CES' current portfolio will reduce to approximately 10,000 MWs 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 that have lowered the value of the business. 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 collateral requirements that otherwise would reduce available liquidity. A lack of viable alternative strategies for its competitive portfolio has and would further stress the financial condition of FES. 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.

As previously disclosed, FES has $130 million of debt maturities that need to be refinanced in 2017 (and $515 million of maturing debt in 2018 beginning in the second quarter). Based on its current senior unsecured debt rating and current capital structure, reflecting the impact of the impairment charges discussed above, as well as the forecasted decline in wholesale forward market prices over the next few years, these debt maturities will be difficult to refinance, even on a secured basis, which would further stress FES' anticipated liquidity. 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 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 may similarly 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 legislative efforts to explore a regulatory solution, these obligations and their impact on 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 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 results.

Together, the Regulated Transmission and Distribution businesses 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 which was implemented on January 1, 2017 to support investment in modernization of the Ohio Companies' distribution systems.

With more than 24,000 miles in operations, the transmission system is the centerpiece of FirstEnergy's regulated investment strategy. Rate base is expected to grow 9% over the next five years 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 and proposed forward-looking formula rates including ATSI, TrAIL, MAIT (which include the transmission assets of ME and PN, effective January 31, 2017), and JCP&L. Filings were made with FERC on October 28, 2016 to implement and transition to a forward-looking formula rate for MAIT's and JCP&L's transmission investments. 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. In 2016, eight of the ten Utilities completed rate proceedings which will provide benefits to the customers and communities those Utilities serve while providing for additional growth opportunities, such as 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 which became effective January 1, 2017, (ii) the PAPUC-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

	For the Years Ended December 31			Increase (Decrease)			
(In millions, except per share amounts)	2016	2015	2014	2016 vs 2015		2015 vs 2014	
REVENUES:	$ 14,562	$ 15,026	$ 15,049	$ (464)	(3)%	$ (23)	— %
OPERATING EXPENSES:							
Fuel	1,666	1,855	2,280	(189)	(10)%	(425)	(19)%
Purchased power	3,813	4,318	4,716	(505)	(12)%	(398)	(8)%
Other operating expenses	3,858	3,749	3,962	109	3 %	(213)	(5)%
Pension and OPEB mark-to-market adjustment	147	242	835	(95)	(39)%	(593)	(71)%
Provision for depreciation	1,313	1,282	1,220	31	2 %	62	5 %
Amortization of regulatory assets, net	320	268	12	52	19 %	256	NM
General taxes	1,042	978	962	64	7 %	16	2 %
Impairment of assets	10,665	42	—	10,623	NM	42	NM
Total operating expenses	22,824	12,734	13,987	10,090	79 %	(1,253)	(9)%
OPERATING INCOME (LOSS)	(8,262)	2,292	1,062	(10,554)	NM	1,230	NM
OTHER INCOME (EXPENSE):							
Investment income (loss)	84	(22)	72	106	NM	(94)	NM
Impairment of equity method investment	—	(362)	—	362	(100)%	(362)	NM
Interest expense	(1,157)	(1,132)	(1,081)	(25)	2 %	(51)	5 %
Capitalized financing costs	103	117	118	(14)	(12)%	(1)	(1)%
Total other expense	(970)	(1,399)	(891)	429	(31)%	(508)	57 %
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(9,232)	893	171	(10,125)	NM	722	NM
INCOME TAXES (BENEFITS)	(3,055)	315	(42)	(3,370)	NM	357	NM
INCOME (LOSS) FROM CONTINUING OPERATIONS	(6,177)	578	213	(6,755)	NM	365	NM
Discontinued operations (net of income taxes of $69)	—	—	86	—	— %	(86)	(100)%
NET INCOME (LOSS)	$ (6,177)	$ 578	$ 299	$ (6,755)	NM	$ 279	93 %
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:							
Basic - Continuing Operations	$ (14.49)	$ 1.37	$ 0.51	$ (15.86)	NM	$ 0.86	NM
Basic - Discontinued Operations	—	—	0.20	—	— %	(0.20)	(100)%
Basic - Net Income (Loss)	$ (14.49)	$ 1.37	$ 0.71	$ (15.86)	NM	$ 0.66	93 %
Diluted - Continuing Operations	$ (14.49)	$ 1.37	$ 0.51	$ (15.86)	NM	$ 0.86	NM
Diluted - Discontinued Operations	—	—	0.20	—	— %	(0.20)	(100)%
Diluted - Net Income (Loss)	$ (14.49)	$ 1.37	$ 0.71	$ (15.86)	NM	$ 0.66	93 %

NM - Not Meaningful

FirstEnergy’s net loss in 2016 was $(6,177) million, or a basic and diluted loss of $(14.49) per share of common stock, compared with net income of $578 million, or basic and diluted earnings of $1.37 per share of common stock in 2015, and $299 million, or basic and diluted earnings of $0.71 per share of common stock in 2014. Highlights of the key changes in year-over-year financial results are included below:

<u>2016 compared with 2015</u>

FirstEnergy's operating results in 2016 decreased $6,755 million as compared to 2015, primarily reflecting pre-tax impairment charges of $10,665 million recognized in 2016, as discussed in the "Executive Summary" above, including the following:

- The impairment of $800 million of goodwill at CES in the second quarter of 2016, reflecting a weak outlook for energy and capacity markets.
- Impairment charges totaling $647 million in the second quarter of 2016 resulting from management's decision to exit the Bay Shore Unit 1 generating station and Units 1-4 of the W.H. Sammis generating station.
- Impairment charges of $9,218 million resulting from management's plans to exit competitive operations by mid-2018 and the anticipated cash flows over this shortened period.

Additionally, the Company recognized valuation allowances against state and local NOL carryforwards of $168 million as further discussed below.

FirstEnergy’s 2016 revenues decreased $464 million as compared to the same period in 2015, resulting from a $835 million decrease at CES, partially offset by an increases of $47 million and $97 million at Regulated Distribution and Regulated Transmission, respectively.

- The decrease in revenue at CES resulted from a 15 million MWH decline in contract sales, as the segment continues to align sales to its generation, as well as lower capacity revenue associated with lower capacity auction prices. The decline in contract sales volume was partially offset by higher wholesale sales and higher net gains on financially settled contracts.
- The increase in revenue at Regulated Transmission primarily reflect recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by adjustments associated with ATSI and TrAIL's annual rate filing for costs previously recovered as well as a lower ROE in 2016 at ATSI under its FERC-approved comprehensive settlement related to the implementation of its forward-looking rate.
- The increase in revenue at Regulated Distribution primarily resulted from higher weather-related distribution deliveries and the full year impact of net rate increases implemented in 2015, partially offset by lower generation sales. Distribution deliveries increased 0.3%, or 0.4 million MWHs, reflecting higher weather-related sales partially offset by the impact of lower weather-adjusted average customer usage reflecting the impact of more energy efficient products and services.

Operating expenses increased $10,090 million in 2016 as compared to 2015, reflecting increases at CES of $9,799 million, primarily associated with the asset impairment charges discussed above, and Regulated Transmission of $77 million, partially offset by a decrease of $50 million at Regulated Distribution.

Changes in certain operating expenses include the following:

- Purchased power decreased $505 million mainly due to lower volumes at CES and Regulated Distribution and lower capacity expense at CES.
- Fuel expense decreased $189 million mainly resulting from lower generation at CES associated with outages and lower economic dispatch of fossil units reflecting low wholesale spot market energy prices, as well as lower unit prices on fossil fuel contracts.
- Pension and OPEB mark-to-market adjustments decreased $95 million to $147 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate used to measure benefit obligations partially offset by higher than expected asset returns and changes in certain actuarial assumptions.
- Other operating expenses increased $109 million, primarily reflecting an increase at Regulated Distribution resulting from the recognition of economic development and energy efficiency obligations in accordance with the PUCO's order approving the Ohio Companies' ESP IV, higher network transmission expenses, which are recovered through transmission rates, higher retirement benefit costs, and higher operating and maintenance expenses associated with storm restoration costs, partially offset by lower PJM transmission costs and lower nuclear planned outage costs at CES.

Other expense decreased $429 million, primarily due to the absence of a $362 million pre-tax impairment charge associated with FEV's investment in Global Holding recognized in 2015 and lower OTTI on NDT investments.

FirstEnergy’s 2016 effective tax rate was 33.1% on pre-tax losses as compared to 35.3% on pre-tax income in 2015. The change primarily relates to the $800 million impairment of goodwill, of which $433 million was non-deductible for tax purposes. Additionally, $168 million of valuation allowances were recorded against state and local NOL carryforwards and $78 million of valuation allowances were recorded against state and local property deferred tax assets, that management believes, more likely than not, will not be realized.

<u>2015 compared with 2014</u>

FirstEnergy’s 2015 income from continuing operations increased $365 million as compared to 2014, resulting from a year-over-year improvement of $506 million at CES, $155 million at Regulated Distribution and $73 million at Regulated Transmission.

In 2015, FirstEnergy’s revenues decreased $23 million as compared to 2014, primarily resulting from a $905 million decrease at CES partially offset by a $528 million increase at Regulated Distribution and a $237 million increase at Regulated Transmission.

- The decrease in revenue at CES resulted from a 31 million MWHs decline in contract sales, in line with CES’ strategy to align sales to its generation, partially offset by higher wholesale sales, including increased capacity revenue associated with higher capacity auction prices.
- The increase in revenue at Regulated Distribution resulted from the implementation of new rates at certain operating companies as well as a year-over-year increase in generation revenue. Distribution deliveries decreased 0.8%, or 1.1 million MWHs, as weather adjusted sales declined as a result of energy efficiency products and services and decreases in certain industrial sectors, partially offset by an increase in weather-related sales.
- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses as well as ATSI’s transition to a forward-looking rate, effective January 1, 2015. These increases were partially offset by a lower ROE at ATSI in the last six months of 2015 as part of its FERC-approved settlement discussed above.

Operating expenses decreased $1,253 million in 2015 as compared to 2014, including a $593 million decrease in the Company's Pension and OPEB mark-to-market adjustment, reflecting a decrease at CES of $1,747 million, partially offset by increases at Regulated Distribution and Regulated Transmission of $257 million and $71 million, respectively.

Changes in certain operating expenses include the following:

- Fuel expense declined $425 million, primarily at CES, resulting from lower fossil generation associated with low energy prices, lower unit costs, and lower settlement and termination charges on fuel and transportation contracts.
- Purchased power decreased $398 million, primarily reflecting lower volumes at CES, resulting from lower contract sales, partially offset by higher volumes at Regulated Distribution due to lower customer shopping as discussed above, and higher capacity expense associated with higher capacity rates.
- Other operating expenses decreased $213 million, primarily reflecting a decrease at CES associated with lower PJM transmission costs and retail-related costs partially offset by higher nuclear planned outage costs. Regulated Distribution other operating expenses increased $163 million resulting from higher network transmission expenses, which are recovered through transmission rates, and higher operating and maintenance expenses associated with reliability improvements.
- Amortization of regulatory assets, net increased $256 million primarily reflecting the recovery of deferred costs, including storm costs, associated with the implementation of new rates discussed above.

FirstEnergy's other expenses increased $508 million, or 57%, year-over-year, primarily resulting from a $362 million pre-tax, non-cash impairment charge associated with FEV’s investment in Global Holding, lower investment income, including a $65 million increase in OTTI on NDT investments, and higher interest expense associated with higher average debt levels.

FirstEnergy’s effective tax rate on income from continuing operations was 35.3% in 2015 compared to (24.6)% in 2014. The increase in the effective tax rate was attributable to tax planning initiatives executed during 2014, including tax benefits associated with an IRS approved change in accounting method for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain state tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. A reconciliation of segment financial results is provided in Note 19, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

During the fourth quarter of 2016, FirstEnergy modified its segment reporting to reclassify the results of operations from certain transmission assets of ME, PN and JCP&L, from the Regulated Distribution segment to the Regulated Transmission segment. Costs associated with these transmission assets, which are currently included in ME, PN, and JCP&L's stated rates, will be recovered through MAIT's and JCP&L's formula rates prospectively, once approved by FERC. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2015 and 2014 have been revised to conform to the current presentation reflecting the operating activity of the identified transmission assets within Regulated Transmission.

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

				Increase (Decrease)	
	2016	2015	2014	2016 vs 2015	2015 vs 2014
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 651	$ 588	$ 433	$ 63	$ 155
Regulated Transmission	331	328	255	3	73
Competitive Energy Services	(6,919)	89	(331)	(7,008)	420
Corporate/Other [1]	(240)	(427)	(58)	187	(369)
Net Income (Loss)	$ (6,177)	$ 578	$ 299	$ (6,755)	$ 279
Basic Earnings (Losses) Per Share:					
Continuing operations	$ (14.49)	$ 1.37	$ 0.51	$ (15.86)	$ 0.86
Discontinued operations	—	—	0.20	—	(0.20)
Earnings (loss) per basic share	$ (14.49)	$ 1.37	$ 0.71	$ (15.86)	$ 0.66
Diluted Earnings (Losses) Per Share:					
Continuing operations	$ (14.49)	$ 1.37	$ 0.51	$ (15.86)	$ 0.86
Discontinued operations	—	—	0.20	—	(0.20)
Earnings (loss) per diluted share	$ (14.49)	$ 1.37	$ 0.71	$ (15.86)	$ 0.66

[1] Includes Corporate support costs not charged to FE's subsidiaries and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes 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.

Summary of Results of Operations — 2016 Compared with 2015

Financial results for FirstEnergy's business segments in 2016 and 2015 were as follows:

2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,401	$ 1,151	$ 3,892	$ (181)	$ 14,263
Other	228	—	178	(107)	299
Internal	—	—	479	(479)	—
Total Revenues	9,629	1,151	4,549	(767)	14,562
Operating Expenses:					
Fuel	567	—	1,099	—	1,666
Purchased power	3,273	—	1,019	(479)	3,813
Other operating expenses	2,436	161	1,526	(265)	3,858
Pension and OPEB mark-to-market adjustment	101	1	45	—	147
Provision for depreciation	676	187	387	63	1,313
Amortization of regulatory assets, net	313	7	—	—	320
General taxes	720	153	134	35	1,042
Impairment of assets	—	—	10,665	—	10,665
Total Operating Expenses	8,086	509	14,875	(646)	22,824
Operating Income (Loss)	1,543	642	(10,326)	(121)	(8,262)
Other Income (Expense):					
Investment income	49	—	66	(31)	84
Impairment of equity method investment	—	—	—	—	—
Interest expense	(586)	(158)	(194)	(219)	(1,157)
Capitalized financing costs	20	34	37	12	103
Total Other Expense	(517)	(124)	(91)	(238)	(970)
Income (Loss) Before Income Taxes (Benefits)	1,026	518	(10,417)	(359)	(9,232)
Income taxes (benefits)	375	187	(3,498)	(119)	(3,055)
Net Income (Loss)	$ 651	$ 331	$ (6,919)	$ (240)	$ (6,177)

2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,386	$ 1,054	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,582	1,054	5,384	(994)	15,026
Operating Expenses:					
Fuel	533	—	1,322	—	1,855
Purchased power	3,548	—	1,456	(686)	4,318
Other operating expenses	2,240	156	1,670	(317)	3,749
Pension and OPEB mark-to-market adjustment	179	3	60	—	242
Provision for depreciation	664	164	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of assets	8	—	34	—	42
Total Operating Expenses	8,136	432	5,076	(910)	12,734
Operating Income	1,446	622	308	(84)	2,292
Other Income (Expense):					
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(600)	(147)	(192)	(193)	(1,132)
Capitalized financing costs	25	44	39	9	117
Total Other Expense	(533)	(103)	(169)	(594)	(1,399)
Income Before Income Taxes	913	519	139	(678)	893
Income taxes	325	191	50	(251)	315
Net Income	$ 588	$ 328	$ 89	$ (427)	$ 578

Changes Between 2016 and 2015 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 15	$ 97	$ (601)	$ (8)	$ (497)
Other	32	—	(27)	28	33
Internal	—	—	(207)	207	—
Total Revenues	47	97	(835)	227	(464)
Operating Expenses:					
Fuel	34	—	(223)	—	(189)
Purchased power	(275)	—	(437)	207	(505)
Other operating expenses	196	5	(144)	52	109
Pension and OPEB mark-to-market adjustment	(78)	(2)	(15)	—	(95)
Provision for depreciation	12	23	(7)	3	31
Amortization of regulatory assets, net	52	—	—	—	52
General taxes	17	51	(6)	2	64
Impairment of assets	(8)	—	10,631	—	10,623
Total Operating Expenses	(50)	77	9,799	264	10,090
Operating Income (Loss)	97	20	(10,634)	(37)	(10,554)
Other Income (Expense):					
Investment income	7	—	82	17	106
Impairment of equity method investment	—	—	—	362	362
Interest expense	14	(11)	(2)	(26)	(25)
Capitalized financing costs	(5)	(10)	(2)	3	(14)
Total Other Expense	16	(21)	78	356	429
Income (Loss) Before Income Taxes (Benefits)	113	(1)	(10,556)	319	(10,125)
Income taxes (benefits)	50	(4)	(3,548)	132	(3,370)
Net Income (Loss)	$ 63	$ 3	$ (7,008)	$ 187	$ (6,755)

Regulated Distribution — 2016 Compared with 2015

Regulated Distribution's net income increased $63 million in 2016 compared to 2015, including a $78 million decrease in its Pension and OPEB mark-to-market adjustment, partially offset by regulatory charges of $51 million resulting from the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV. Excluding the impact of these adjustments, year-over-year earnings reflect higher distribution deliveries and the full year impact of net rate increases implemented in 2015 as a result of approved rate cases at certain of the Utilities, as further described below, partially offset by higher retirement benefit costs and other operating expenses.

Revenues —

The $47 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In millions)		
Distribution services	$ 4,785	$ 4,510	$ 275
Generation sales:			
Retail	4,119	4,303	(184)
Wholesale	497	573	(76)
Total generation sales	4,616	4,876	(260)
Other	228	196	32
Total Revenues	$ 9,629	$ 9,582	$ 47

Distribution services revenues increased $275 million primarily resulting from the full year impact of approved base distribution rate increases at the Pennsylvania Companies, effective May 3, 2015, and MP and PE in West Virginia, effective February 25, 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 1, 2015. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs as well as higher weather-related usage, as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31 2016	2015	Increase (Decrease)
	(In thousands)		
Residential	54,840	54,466	0.7 %
Commercial	43,340	43,091	0.6 %
Industrial	50,082	50,269	(0.4)%
Other	579	585	(1.0)%
Total Electric Distribution MWH Deliveries	148,841	148,411	0.3 %

Higher distribution deliveries to residential and commercial customers reflect increased weather-related usage resulting from cooling degree days that were 18% above 2015, and 37% above normal, partially offset by heating degree days that were 6% below 2015, and 9% below normal. Additionally, distribution deliveries to residential and commercial customers were impacted by declining average customer usage associated with more energy efficient products and services. Year-to-date deliveries to industrial customers declined slightly as the increase from shale customer usage was more than offset by a decrease from steel and chemical customer usage.

The following table summarizes the price and volume factors contributing to the $260 million decrease in generation revenues in 2016, as compared to 2015:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (196)
Change in prices	12
	(184)
Wholesale:	
Effect of increase in sales volumes	47
Change in prices	(107)
Capacity revenue	(16)
	(76)
Decrease in Generation Revenues	$ (260)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania, and New Jersey. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 83% from 80% for the Ohio Companies, to 67% from 65% for the Pennsylvania Companies and to 51% from 50% for JCP&L. The increase in retail generation prices primarily resulted from an ENEC rate increase in West Virginia, effective January 1, 2016, partially offset by lower default service auction prices in Ohio and Pennsylvania.

Wholesale generation revenues decreased $76 million in 2016 compared to the same period of 2015, primarily due to lower spot market energy prices, partially offset by higher wholesale sales. The difference between current wholesale generation revenues and certain energy costs incurred is deferred for future recovery or refund, with no material impact to earnings.

Other revenues increased $32 million, primarily related to a $29 million gain on the sale of oil and gas rights at WP.

Operating Expenses —

Total operating expenses decreased $50 million primarily due to the following:

- Fuel expense increased $34 million in 2016, as compared to the same period of 2015, primarily related to higher generation.

- Purchased power costs decreased $275 million in 2016, as compared to the same period of 2015, primarily due to lower volumes resulting from increased customer shopping, as described above, as well as lower unit costs reflecting lower default service auction prices in Ohio and Pennsylvania.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (133)
Change due to decreased volumes	(6)
	(139)
Purchases from affiliates:	
Change due to decreased unit costs	(2)
Change due to decreased volumes	(204)
	(206)
Capacity expense	(5)
Amortization of deferred costs	75
Decrease in Purchased Power Costs	$ (275)

- Other operating expenses increased $196 million primarily due to:
  - An increase of $51 million resulting from the recognition of economic development and energy efficiency obligations in accordance with the PUCO's March 31, 2016 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.
  - Higher retirement benefit costs of $57 million.
  - Higher transmission expenses of $56 million primarily related to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The difference between current revenues and transmission costs incurred are deferred for future recovery or refund, resulting in no material impact on current period earnings.
  - Higher operating and maintenance expense of $33 million, primarily due to increased storm restoration costs, which are deferred for future recovery resulting in no material impact on current period earnings.

- Pension and OPEB mark-to-market adjustments decreased $78 million to $101 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate used to measure benefit obligations partially offset by higher than expected asset returns and changes in certain actuarial assumptions.

- Depreciation expenses increased $12 million due to a higher asset base.

- Net amortization of regulatory assets increased $52 million primarily due to:
  - A full year recovery of storm costs in New Jersey, Pennsylvania, and West Virginia, effective with the implementation of new rates as discussed above ($35 million),
  - Recovery of West Virginia vegetation management program costs ($40 million), partially offset by
  - Higher deferral of storm restoration costs ($39 million).

- General taxes increased $17 million primarily due to higher revenue-related taxes in Pennsylvania and higher property taxes in Ohio.

Other Expense —

Total other expense decreased $16 million primarily related to lower interest expense resulting from various debt maturities at JCP&L and OE in 2016.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.5% and 35.6% for 2016 and 2015, respectively.

Regulated Transmission — 2016 Compared with 2015

Net income increased $3 million in 2016 compared to 2015, primarily resulting from a higher rate base, partially offset by adjustments associated with ATSI and TrAIL's annual rate filing for costs previously recovered, a lower return on equity at ATSI, and lower capitalized financing costs.

Revenues —

Total revenues increased $97 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by adjustments associated with ATSI's and TrAIL's annual rate filing for costs previously recovered as well as a lower ROE at ATSI under its FERC-approved comprehensive settlement related to the implementation of its forward-looking rate effective January 1, 2015.

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

Revenues by Transmission Asset Owner	For the Years Ended December 31 2016	2015	Increase (Decrease)
		(In millions)	
ATSI	$ 540	$ 446	$ 94
TrAIL	252	252	—
PATH	12	13	(1)
Utilities	347	343	4
Total Revenues	$ 1,151	$ 1,054	$ 97

Operating Expenses —

Total operating expenses increased $77 million principally due to higher property taxes and depreciation expense at ATSI, which are recovered through ATSI's forward-looking formula rate.

Other Expenses —

Other expense increased $21 million in 2016, as compared to 2015, primarily due to lower capitalized financing costs resulting from lower construction work in progress balances at ATSI as well as increased interest expense resulting from a long-term debt issuance of $150 million at ATSI in the fourth quarter of 2015, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.1% and 36.8% for 2016 and 2015, respectively.

CES — 2016 Compared with 2015

Operating results decreased $7,008 million in 2016 compared to 2015, primarily resulting from pre-tax asset impairment charges of $10,665 million discussed above, partially offset by lower mark-to-market gains on commodity contract positions, a lower Pension and OPEB mark-to-market adjustment and lower settlement and termination costs related to coal contracts. Excluding these items, year-over-year operating results were impacted by lower capacity revenues, lower sales volumes, a termination charge associated with an FES customer contract, and higher retirement and employee benefit costs, partially offset by lower fuel costs, reduced transmission expenses, and lower purchased power.

Revenues —

Total revenues decreased $835 million in 2016, as compared to 2015, primarily due to decreased sales volumes and lower capacity revenue, partially offset by higher net gains on financially settled contracts and an increase in short-term (net hourly position) transactions, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31		Increase (Decrease)
	2016	2015	
	(In millions)		
Contract Sales:			
Direct	$ 812	$ 1,269	$ (457)
Governmental Aggregation	814	1,012	(198)
Mass Market	169	265	(96)
POLR	583	712	(129)
Structured Sales	463	558	(95)
Total Contract Sales	2,841	3,816	(975)
Wholesale	1,457	1,225	232
Transmission	73	138	(65)
Other	178	205	(27)
Total Revenues	$ 4,549	$ 5,384	$ (835)

MWH Sales by Channel	For the Years Ended December 31		Increase (Decrease)
	2016	2015	
	(In thousands)		
Contract Sales:			
Direct	15,310	23,585	(35.1)%
Governmental Aggregation	13,730	15,443	(11.1)%
Mass Market	2,431	3,878	(37.3)%
POLR	9,969	11,950	(16.6)%
Structured Sales	11,414	12,902	(11.5)%
Total Contract Sales	52,854	67,758	(22.0)%
Wholesale	15,201	7,326	107.5 %
Total MWH Sales	68,055	75,084	(9.4)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	**Sales Volumes**	**Prices**	**Gain on Settled Contracts**	**Capacity Revenue**	**Total**
			(In millions)		
Direct	$ (445)	$ (12)	$ —	$ —	$ (457)
Governmental Aggregation	(112)	(86)	—	—	(198)
Mass Market	(99)	3	—	—	(96)
POLR	(118)	(11)	—	—	(129)
Structured Sales	(64)	(31)	—	—	(95)
Wholesale	223	(10)	98	(79)	232

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflects the continuation of FES' strategy to more effectively hedge its generation, as discussed above. The Direct, Governmental Aggregation, and Mass Market customer base was 1.1 million as of December 31, 2016, compared to 1.6 million as of December 31, 2015. Although unit pricing was lower year-over-year in the Direct and Governmental Aggregation channels, the decrease was primarily attributable to lower capacity expenses, as discussed below, which is a component of the retail price.

The decrease in POLR sales of $129 million was primarily due to lower volumes. Structured Sales decreased $95 million, primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues increased $232 million, primarily due to an increase in short-term (net hourly position) transactions and higher net gains on financially settled contracts, partially offset by a decrease in capacity revenue from lower capacity auction prices and lower spot market energy prices.

Transmission revenue decreased $65 million, primarily due to lower congestion revenue associated with less volatile market conditions.

Other revenue decreased $27 million, primarily due to the absence of a gain on the sale of property to a regulated affiliate in 2015 and lower lease revenues from the expiration of a nuclear sale-leaseback agreement.

Operating Expenses —

Total operating expenses increased $9,799 million in 2016 due to the following:

- Fuel costs decreased $223 million, primarily due to lower generation associated with outages and lower economic dispatch of fossil units resulting from low wholesale spot market energy prices, as discussed above, as well as lower unit prices on fossil fuel contracts. Additionally, fuel costs were impacted by lower settlement and termination costs on coal contracts. The impact of settlements and terminations of coal contracts resulted in a pre-tax loss of $58 million and $67 million in 2016 and 2015, respectively.

- Purchased power costs decreased $437 million due to lower capacity expenses ($234 million) and lower volumes ($203 million). The decrease in capacity expense, which is a component of CES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with CES' retail sales obligations. Lower volumes primarily resulted from lower contract sales, as discussed above, partially offset by higher economic purchases, resulting from the low wholesale spot market price environment.

- Fossil operating costs increased $4 million, primarily due to increased outage costs and higher employee benefit costs, partially offset by lower operating costs from the deactivation of certain fossil plants in April 2015.

- Nuclear operating costs decreased $39 million, primarily as a result of lower refueling outage costs, partially offset by higher employee benefit costs. There were two refueling outages in 2016 as compared to three refueling outages in 2015.

- Retirement benefit costs increased $31 million.

- Transmission expenses decreased $175 million, primarily due to lower congestion and market-based ancillary costs associated with less volatile market conditions as compared to 2015, as well as lower load requirements.

- Other operating expenses increased $35 million, primarily due to lower mark-to-market gains on commodity contract positions of $84 million and a $37 million charge associated with the termination of an FES customer contract, partially offset by lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement.

- Pension and OPEB mark-to-market adjustments decreased $15 million to $45 million in 2016. The 2016 adjustment resulted from a 25 bps decrease in the discount rate used to measure benefit obligations, partially offset by higher than expected asset returns and changes in other actuarial assumptions.

- Depreciation expense decreased $7 million, primarily as a result of an out-of-period adjustment to reduce depreciation of a hydroelectric generating station, partially offset by a higher asset base.

- General taxes decreased $6 million, primarily due to lower gross receipts taxes associated with lower retail sales volumes.

- Impairment of assets increased $10,631 million, primarily due to impairments of goodwill and the competitive generation assets discussed above.

Other Expense —

Total other expense decreased $78 million in 2016 compared to 2015 primarily due to lower OTTI on NDT investments.

Income Taxes (Benefits) —

CES' effective tax rate was 33.6% on pre-tax losses and 36.0% on pre-tax income for 2016 and 2015, respectively. The change in the effective tax rate is primarily due to $168 million of valuation allowances recorded against state and local NOL carryforwards and $78 million of valuation allowances recorded against state and local property deferred tax assets, that management believes, more likely than not, will not be realized, as well as the impairment of $800 million of goodwill, of which $433 million is non-deductible for tax purposes.

Corporate/Other — 2016 Compared with 2015

Financial results and reconciling items included in Corporate/Other resulted in a $187 million increase in net income in 2016 compared to 2015 primarily due to the absence of a $362 million pre-tax impairment of FirstEnergy's equity method investment in Global Holding recognized in 2015. Excluding the impact of this adjustment, year-over-year results were impacted by higher operating and maintenance costs, higher interest expense and changes in the consolidated effective tax rate, which for 2016 was 33.1% on pre-tax losses and for 2015 was 35.5% on pre-tax income. The increased interest expense primarily relates to debt redemption costs related to the FE revolving credit facility and term loans, as discussed in "Capital Resources and Liquidity". The higher consolidated effective tax rate primarily resulted from the absence of tax benefits recognized in 2015 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, as well as from changes in state apportionment factors.

Summary of Results of Operations — 2015 Compared with 2014

Financial results for FirstEnergy's business segments in 2015 and 2014 were as follows:

2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,386	$ 1,054	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,582	1,054	5,384	(994)	15,026
Operating Expenses:					
Fuel	533	—	1,322	—	1,855
Purchased power	3,548	—	1,456	(686)	4,318
Other operating expenses	2,240	156	1,670	(317)	3,749
Pension and OPEB mark-to-market adjustment	179	3	60	—	242
Provision for depreciation	664	164	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of assets	8	—	34	—	42
Total Operating Expenses	8,136	432	5,076	(910)	12,734
Operating Income	1,446	622	308	(84)	2,292
Other Income (Expense):					
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(600)	(147)	(192)	(193)	(1,132)
Capitalized interest	25	44	39	9	117
Total Other Expense	(533)	(103)	(169)	(594)	(1,399)
Income From Continuing Operations Before Income Taxes	913	519	139	(678)	893
Income taxes	325	191	50	(251)	315
Income From Continuing Operations	588	328	89	(427)	578
Discontinued Operations, net of tax	—	—	—	—	—
Net Income	$ 588	$ 328	$ 89	$ (427)	$ 578

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,850	$ 817	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,054	817	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,077	143	2,075	(333)	3,962
Pension and OPEB mark-to-market adjustment	506	2	327	—	835
Provision for depreciation	651	134	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	692	71	171	28	962
Impairment of assets	—	—	—	—	—
Total Operating Expenses	7,879	361	6,823	(1,076)	13,987
Operating Income (Loss)	1,175	456	(534)	(35)	1,062
Other Income (Expense):					
Investment income	56	—	54	(38)	72
Impairment of equity method investment	—	—	—	—	—
Interest expense	(603)	(117)	(197)	(164)	(1,081)
Capitalized interest	14	55	37	12	118
Total Other Expense	(533)	(62)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	642	394	(640)	(225)	171
Income taxes (benefits)	209	139	(223)	(167)	(42)
Income (Loss) From Continuing Operations	433	255	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 433	$ 255	$ (331)	$ (58)	$ 299

Changes Between 2015 and 2014 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 536	$ 237	$ (788)	$ 20	$ 5
Other	(8)	—	16	(36)	(28)
Internal	—	—	(133)	133	—
Total Revenues	528	237	(905)	117	(23)
Operating Expenses:					
Fuel	(34)	—	(391)	—	(425)
Purchased power	163	—	(694)	133	(398)
Other operating expenses	163	13	(405)	16	(213)
Pension and OPEB mark-to-market adjustment	(327)	1	(267)	—	(593)
Provision for depreciation	13	30	7	12	62
Amortization of regulatory assets, net	260	(4)	—	—	256
General taxes	11	31	(31)	5	16
Impairment of assets	8	—	34	—	42
Total Operating Expenses	257	71	(1,747)	166	(1,253)
Operating Income	271	166	842	(49)	1,230
Other Income (Expense):					
Investment loss	(14)	—	(70)	(10)	(94)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	3	(30)	5	(29)	(51)
Capitalized interest	11	(11)	2	(3)	(1)
Total Other Expense	—	(41)	(63)	(404)	(508)
Income From Continuing Operations Before Income Taxes	271	125	779	(453)	722
Income taxes	116	52	273	(84)	357
Income From Continuing Operations	155	73	506	(369)	365
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income	$ 155	$ 73	$ 420	$ (369)	$ 279

Regulated Distribution — 2015 Compared with 2014

Regulated Distribution's net income increased $155 million in 2015 compared to 2014, including a $327 million decrease in its Pension and OPEB mark-to-market adjustment. Excluding the impact of this adjustment, year-over-year earnings were impacted by increased operating expenses, including higher reliability maintenance expenses, higher benefit costs, and higher depreciation associated with increased capital investments, and a higher effective tax rate, partially offset by a net increase in new rates implemented in 2015 at certain of the Utilities.

Revenues —

The $528 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2015	2014	Increase (Decrease)
		(In millions)	
Distribution services	$ 4,510	$ 4,056	$ 454
Generation sales:			
Retail	4,303	4,043	260
Wholesale	573	751	(178)
Total generation sales	4,876	4,794	82
Other	196	204	(8)
Total Revenues	$ 9,582	$ 9,054	$ 528

Distribution services revenues increased $454 million primarily resulting from approved base distribution rate increases at the Pennsylvania Companies, effective May 3, 2015, and at MP and PE in West Virginia, effective February 25, 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 1, 2015. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs, as well as higher weather-related usage, as described below. Partially offsetting these items were the impacts of lower residential and industrial customer usage as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	54,466	54,766	(0.5)%
Commercial	43,091	42,925	0.4 %
Industrial	50,269	51,276	(2.0)%
Other	585	586	(0.2)%
Total Electric Distribution MWH Deliveries	148,411	149,553	(0.8)%

Lower deliveries to residential customers, reflect declining weather-adjusted average customer usage due, in part, to increasing energy efficiency products and services as well as heating degree days that were 10.8% below the same period in 2014 and 2.8% below normal, partially offset by cooling degree days that were 32% above 2014 and 17% above normal. Commercial sales increased year-over-year from the increase in cooling degree days, partially offset by the lower heating degree days as well as decreased weather-adjusted average customer usage similar to the impact to residential customers. Deliveries to industrial customers decreased 2%, as the increase from shale and petroleum customer usage was more than offset by a decrease from steel and mining customer usage.

The following table summarizes the price and volume factors contributing to the $82 million increase in generation revenues in 2015 compared to 2014:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 146
Change in prices	114
	260
Wholesale:	
Effect of decrease in sales volumes	(151)
Change in prices	(82)
Capacity revenue	55
	(178)
Increase in Generation Revenues	$ 82

The increase in retail generation sales volume was primarily due to lower customer shopping in Ohio, Pennsylvania, and New Jersey and an increase in weather-related usage, partially offset by the impacts of energy efficiency as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 80% from 81% for the Ohio Companies, 65% from 67% for the Pennsylvania Companies and 50% from 52% for JCP&L. The increase in prices primarily resulted from higher default service auction prices.

Wholesale generation revenue decreased $178 million in 2015 compared to 2014, primarily reflecting decreased volume associated with the termination of certain NUG contracts at JCP&L and PN and lower economic dispatch of fossil generating units associated with low spot market energy prices. Partially offsetting the decrease was an increase in capacity revenue resulting from higher capacity prices. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery, with no material impact on earnings.

Operating Expenses —

Total operating expenses increased $257 million primarily due to the following:

- Fuel expense decreased $34 million in 2015 primarily related to lower economic dispatch resulting from low spot market energy prices.

- Purchased power costs were $163 million higher in 2015 primarily due to increased volumes reflecting lower customer shopping as described above, higher unit costs related to higher default service auction prices, and higher capacity expense at MP, partially offset by lower volumes resulting from the termination of certain NUG contracts at JCP&L and PN.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 66
Change due to increased volumes	185
	251
Purchases from affiliates:	
Change due to decreased unit costs	(21)
Change due to decreased volumes	(113)
	(134)
Capacity expense	36
Amortization of deferred costs	10
Increase in Purchased Power Costs	$ 163

Other operating expenses increased $163 million primarily due to:

- Higher transmission expenses of $73 million primarily due to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The differences between current retail transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.

- Increased regulated generation operating and maintenance expenses of $7 million, reflecting higher planned outage expenses in 2015 compared to 2014.

- Higher retirement benefit costs of $22 million.

- Higher distribution operating and maintenance expenses of $61 million, reflecting increased reliability maintenance and other employee benefit costs, partially offset by lower storm restoration costs.

- Pension and OPEB mark-to-market adjustments decreased $327 million to $179 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

- Depreciation expense increased $13 million due to a higher asset base, partially offset by lower depreciation rates at JCP&L effective with the implementation of new rates from its distribution base rate case as well as lower depreciation rates in Pennsylvania based on updated asset life studies approved by the PPUC.

- Net regulatory asset amortization increased $260 million primarily due to:

  - Recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above ($66 million),
  - Higher energy efficiency program cost recovery ($66 million),
  - Lower deferral of TTS costs in West Virginia ($37 million),
  - Higher amortizations of above-market NUG costs in Pennsylvania and New Jersey ($36 million),
  - Lower deferral of West Virginia vegetation management expenses ($31 million),
  - Higher default generation service cost amortization ($28 million), and
  - Recovery of Pennsylvania legacy meter costs ($22 million); partially offset by
  - Higher cost deferral of Ohio network transmission expenses ($33 million).

- General taxes increased $11 million primarily due to higher revenue-related taxes in Pennsylvania, partially offset by lower property taxes in Ohio.

Other Expense —

Other expense was flat in 2015 as compared to 2014, as lower investment income was offset by lower interest expense and higher capitalized financing costs.

Income Taxes —

Regulated Distribution's effective tax rate was 35.6% and 32.6% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and tax benefits recognized in 2014.

Regulated Transmission — 2015 Compared with 2014

Net income increased $73 million in 2015 compared to 2014. Higher Transmission revenues associated with ATSI's "forward looking" rate and higher rate base were partially offset by higher interest expense and lower capitalized financing costs.

Revenues —

Total revenues increased $237 million principally at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base. Effective January 1, 2015, ATSI's formula rate transitioned to a "forward looking" approach, where transmission revenues are based on actual costs.

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

	For the Years Ended December 31		
Revenues by Transmission Asset Owner	**2015**	**2014**	**Increase (Decrease)**
		(In millions)	
ATSI	$ 446	$ 242	$ 204
TrAIL	252	214	38
PATH	13	13	—
Utilities	343	348	(5)
Total Revenues	$ 1,054	$ 817	$ 237

Operating Expenses —

Total operating expenses increased $71 million principally due to higher operating and maintenance expenses, depreciation, and property taxes at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expenses —

Other expenses increased $41 million due to increased interest expense resulting from debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings as well as lower capitalized financing costs.

Income Taxes —

Regulated Transmission's effective tax rate was 36.8% and 35.3% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and tax benefits recognized in 2014.

CES — 2015 Compared with 2014

Operating results increased $420 million in 2015, compared to 2014, primarily from higher capacity revenues and the absence of the impact of the high market prices associated with extreme weather events and unplanned outages in 2014 that resulted in higher purchased power and transmission costs, partially offset by lower contract sales volumes. Additionally, changes in year-over-year operating results were impacted by lower Pension and OPEB mark-to-market adjustments, lower settlement and termination costs related to coal and transportation contracts, and the absence of a $78 million after-tax gain on the sale of certain hydroelectric facilities recognized in February 2014.

Revenues —

Total revenues decreased $905 million in 2015, compared to 2014, primarily due to decreased sales volumes. Revenues were also impacted by higher unit prices compared to 2014 as a result of increased channel pricing, as well as higher capacity revenues, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31 2015	2014	Increase (Decrease)
		(In millions)	
Contract Sales:			
Direct	$ 1,269	$ 2,359	$ (1,090)
Governmental Aggregation	1,012	1,184	(172)
Mass Market	265	452	(187)
POLR	712	902	(190)
Structured Sales	558	522	36
Total Contract Sales	3,816	5,419	(1,603)
Wholesale	1,225	461	764
Transmission	138	220	(82)
Other	205	189	16
Total Revenues	$ 5,384	$ 6,289	$ (905)

MWH Sales by Channel	For the Years Ended December 31 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	23,585	44,012	(46.4)%
Governmental Aggregation	15,443	19,569	(21.1)%
Mass Market	3,878	6,773	(42.7)%
POLR	11,950	15,708	(23.9)%
Structured Sales	12,902	12,814	0.7 %
Total Contract Sales	67,758	98,876	(31.5)%
Wholesale	7,326	680	NM
Total MWH Sales	75,084	99,556	(24.6)%

NM - Not Meaningful

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (1,095)	$ 5	$ —	$ —	$ (1,090)
Governmental Aggregation	(249)	77	—	—	(172)
Mass Market	(193)	6	—	—	(187)
POLR	(216)	26	—	—	(190)
Structured Sales	3	33	—	—	36
Wholesale	197	(8)	107	468	764

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflecting FES' strategy to more effectively hedge its generation as discussed above. Although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price, partially offset by a lower energy component of the retail price resulting from lower year-over-year market prices. The Direct, Governmental Aggregation and Mass Market customer base was 1.6 million as of December 31, 2015, compared to 2.1 million as of December 31, 2014.

The decrease in POLR sales of $190 million was due to lower volumes, partially offset by higher rates associated with POLR auctions. Structured Sales increased $36 million due to low market prices that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $764 million, primarily due to an increase in capacity revenue from capacity auctions, increase in short-term (net hourly position) transactions, and higher net gains on financially settled contracts, partially offset by lower spot market energy prices, which limited additional wholesale sales.

Transmission revenue decreased $82 million, primarily due to lower congestion revenue resulting from the market conditions associated with the extreme weather events in 2014.

Other revenue increased $16 million, primarily due to a gain on the sale of property to a regulated affiliate in 2015 and higher lease revenues from additional equity interests in affiliated sale and leasebacks repurchased in November 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $1,747 million in 2015 due to the following:

- Fuel costs decreased $391 million, primarily due to lower economic dispatch of fossil units resulting from low spot market energy prices and lower nuclear unit prices, resulting from the suspension of the DOE nuclear disposal fee, effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. The impact of terminations and settlements of coal and transportation contracts resulted in a pre-tax loss of $67 million and $166 million in 2015 and 2014, respectively.

- Purchased power costs decreased $694 million due to lower volumes ($888 million), partially offset by higher unit prices ($39 million) and higher capacity expenses ($155 million). Lower volumes were primarily due to decreased load requirements resulting from lower sales, as discussed above, partially offset by lower fossil generation, as discussed above. The higher unit prices are primarily due to higher losses on financially settled contracts, partially offset by lower market prices in 2015 as compared to 2014. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.

- Nuclear operating costs increased $84 million as a result of higher refueling outage costs and higher employee benefit expenses. There were three refueling outages in 2015 as compared to two refueling outages in 2014.

- Transmission expenses decreased $273 million, primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in 2014.

- General taxes decreased $31 million, primarily due to lower gross receipts taxes associated with lower retail sales volumes.

- Pension and OPEB mark-to-market adjustments decreased $267 million to $60 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

- Other operating expenses decreased $216 million, primarily due to a $141 million decrease in mark-to-market expenses on commodity contract positions reflecting lower market prices and a $71 million decrease in retail-related costs.

- Impairment of assets were $34 million in 2015 due to impairment charges associated with non-core assets.

Other Expense —

Total other expense increased $63 million in 2015 compared to 2014 primarily due to higher OTTI on NDT investments, partially offset by the absence of an $8 million loss on debt redemptions in 2014.

Discontinued Operations —

There were no discontinued operations in 2015. In 2014, discontinued operations primarily included a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of certain hydroelectric assets on February 12, 2014.

Income Tax (Benefits) —

CES' effective tax rate was 36.0% and 34.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Corporate/Other — 2015 Compared with 2014

Financial results and reconciling items included in Corporate/Other resulted in a $369 million decrease in net income in 2015 compared to 2014 primarily due to a $362 million pre-tax impairment of FirstEnergy's equity method investment in Global Holding, higher costs associated with environmental remediation at legacy plants, higher interest expense and a higher effective tax rate. During 2015, based on the significant decline in coal pricing and the current outlook for the coal market, FirstEnergy assessed the carrying value of its investment in Global Holding and determined there was an other than temporary decline in the fair value below its carrying value, which resulted in the impairment charge. The increased interest expense primarily relates to FE's $1 billion term loan entered into in March 2014 and the absence of a gain on the termination of interest rate swaps in 2014. The higher effective tax rate primarily resulted from the absence of tax benefits recognized in 2014 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, a reduction in state deferred tax liabilities resulting from changes in state apportionment factors, the elimination of certain tax liabilities associated with basis differences as well as certain tax benefits recorded in 2014 that related to prior periods.

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 December 31, 2016 and December 31, 2015, and the changes during the year ended December 31, 2016:

Regulatory Assets (Liabilities) by Source	December 31, 2016	December 31, 2015	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 90	$ 185	$ (95)
Customer receivables for future income taxes	444	355	89
Nuclear decommissioning and spent fuel disposal costs	(304)	(272)	(32)
Asset removal costs	(470)	(372)	(98)
Deferred transmission costs	127	115	12
Deferred generation costs	215	243	(28)
Deferred distribution costs	296	335	(39)
Contract valuations	153	186	(33)
Storm-related costs	353	403	(50)
Other	110	170	(60)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,014	$ 1,348	$ (334)

Regulatory assets that do not earn a current return totaled approximately $153 million and $148 million as of December 31, 2016 and 2015, respectively, primarily related to storm damage costs, and are currently being recovered through rates.

As of December 31, 2016 and December 31, 2015, FirstEnergy had approximately $157 million and $116 million 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 with respect to FES, a two-year secured line of credit with FE of up to $500 million, as further described below. Additionally, FES subsidiaries have debt maturities in 2017 and 2018 of $130 million and $515 million, respectively. The inability to refinance such 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) seek protection under U.S. bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under U.S. bankruptcy laws.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016.

Capital expenditures for 2016 and anticipated expenditures for 2017 and 2018 by reportable segment are included below:

Reportable Segment	2016 Actual[(1)]	2016 Pension/OPEB Mark-to-Market Capital Costs	2016 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2017 Forecast[(2)]	2018 Forecast[(2)]
			(In millions)		
Regulated Distribution	$ 1,327	$ 46	$ 1,281	$ 1,325	$ 1,305
Regulated Transmission[(4)]	1,005	4	1,001	1,000	1,000
CES[(3)]	547	(3)	550	365	290
Corporate/Other	93	—	93	95	90
Total	$ 2,972	$ 47	$ 2,925	$ 2,785	$ 2,685

(1) Includes an increase of approximately $47 million related to the capital component of the pension and OPEB mark-to-market adjustment.

(2) Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.

(3) Approximately $35 million and $20 million of forecasted annual capital expenditures are associated with the Pleasants power station for 2017 and 2018, respectively. On February 3, 2017, AE Supply offered the Pleasants power station into MP's RFP, as discussed above.

(4) 2018 Forecast represents the mid-point of Regulated Transmission's 2018 forecasted capital expenditures of $800 million to $1,200 million.

Capital expenditures for 2016 and anticipated expenditures for 2017 by subsidiary are included in the following table (anticipated capital expenditures by subsidiary for 2018 are not finalized):

Operating Company	2016 Actual[1]	2016 Pension/OPEB Mark-to-Market Capital Costs	2016 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs	2017 Forecast[2]
		(In millions)		
OE	$ 163	$ 7	$ 156	$ 145
Penn	50	3	47	45
CEI	158	25	133	125
TE	46	2	44	45
JCP&L	399	17	382	350
ME	139	6	133	135
PN	184	1	183	160
MP	242	(6)	248	250
PE	103	(5)	108	125
WP	166	—	166	205
ATSI	487	—	487	420
TrAIL	217	—	217	60
FES	470	(3)	473	320
AE Supply[3]	63	—	63	45
MAIT	—	—	—	260
Other subsidiaries	85	—	85	95
Total	$ 2,972	$ 47	$ 2,925	$ 2,785

(1) Includes an increase of approximately $47 million related to the capital component of the pension and OPEB mark-to-market adjustment.

(2) Excludes the capital component for pension and OPEB mark-to-market adjustments, which cannot be estimated.

(3) Approximately $35 million of forecasted annual capital expenditures are associated with the Pleasants power station for 2017. On February 3, 2017, AE Supply offered the Pleasants power station into MP's RFP, as discussed above.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the *Energizing the Future* transmission plan, which FirstEnergy plans to invest $4.2 to $5.8 billion in capital investments from 2017 to 2021, and 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. Through 2016, FirstEnergy's capital expenditures under this plan were $3.4 billion. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2021.

Additionally, planned capital expenditures in 2019 for Regulated Distribution are approximately $1.3 billion primarily to enhance the Utilities' distribution systems.

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, 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, such as the impact of the current energy and capacity markets and potential credit rating changes. 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 it funds any such borrowings through its 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 December 31, 2016, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of December 31, 2016, included the following:

Currently Payable Long-Term Debt		***(In millions)***
FMBs	$	725
Unsecured notes		680
Unsecured PCRBs		158
Collateralized lease obligation bonds		5
Sinking fund requirements		74
Other notes		43
	$	1,685

Short-Term Borrowings / Revolving Credit Facilities

On December 6, 2016, FE and certain subsidiaries entered into new five-year syndicated credit facilities available through December 6, 2021, and concurrently terminated existing syndicated credit facilities that were to expire March 31, 2019, as follows:

- FE and the Utilities entered into a new $4 billion revolving credit facility, which represents an increase of $500 million over the existing $3.5 billion facility it replaced,
- FET and its subsidiaries entered into a $1 billion revolving credit facility, which replaced their existing $1 billion facility, and
- FES and AE Supply terminated their unsecured $1.5 billion credit facility (commitments of $900 million and $600 million for FES and AE Supply, respectively) and FES entered into a new, two-year secured credit facility with FE in which FE provided 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 other bonds as designated in writing to FE. In connection with the cancellation of the prior FES/AE Supply facility and entry into the new FES secured facility with FE, certain commitments and amendments associated with shared services and operational matters were made including, without limitation, as follows: (i) FE reaffirmed its obligations under the Intercompany Tax Allocation Agreement, and (ii) amendments to the Service Agreement by and among FESC, FES, FG and NG, to prevent termination until the earlier of December 31, 2018, or a change in control of FES or its subsidiaries.

FE, the Utilities and FET and its subsidiaries may use borrowings under their new facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. FES expects to use its new facility with FE to conduct its ordinary course of business in lieu of borrowing under the unregulated money pool. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million).

Under the terms of the new FE and FET credit facilities, each borrower is required to maintain a consolidated debt to total capitalization ratio, as defined, of no more than 0.65 to 1.00, or in the case of FET, 0.75 to 1.00. For purposes of calculating its ratio, FE is permitted certain adjustments to total capitalization including (i) an exclusion for certain previously incurred after-tax, non-cash write-downs and non-cash charges of approximately $2.75 billion and (ii) a new exclusion for additional after-tax, non-cash write-downs and non-cash charges up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and each of their subsidiaries. Additionally, under the new credit facility, FE is now also required to maintain a minimum interest coverage ratio of 1.75 to 1.00 until December 31, 2017, 2.00 to 1.00 beginning January 1, 2018 until December 31, 2018, 2.25 to 1.00 beginning January 1, 2019 until December 31, 2019, and 2.50 to 1.00 beginning January 1, 2020 until December 31, 2021. FE and each of the other borrowers under the new FE and FET credit facilities are currently in compliance with these financial covenants. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 described above are excluded from FE's calculation of total capitalization pursuant to the new $5.5 billion after-tax exclusion referenced in (ii) above consistent with the terms of the facility. Other terms of the new FE credit facility exclude FES and AE Supply from the definition of "significant subsidiaries," which removes them from FE's covenants and defaults resulting from adverse judgments in excess of $100 million and eliminates lender approvals previously required for FES and AE Supply asset sales.

Outstanding alternate base rate advances under the new FE and FET facilities will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to the applicable borrower's then-current senior unsecured non-credit enhanced debt ratings (reference ratings) plus the highest of (i) the "prime rate" published by the Wall Street Journal from time to time, (ii) the sum of 1/2 of 1% per annum plus the federal funds rate in effect from time to time and (iii) the LIBOR for a one-month interest period plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to the applicable borrower's reference ratings. Swing line loans under the new FE facility will bear interest at a rate per annum equal to the sum of the alternate base rate plus an applicable margin determined by reference to the applicable borrower's reference ratings. Changes in reference ratings of a borrower would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

FirstEnergy had $2,675 million and $1,708 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FirstEnergy's available liquidity from external sources as of January 31, 2017 was as follows:

Borrower(s)	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy[(1)]	Revolving	December 2021	$ 4,000	$ 1,341
FET[(2)]	Revolving	December 2021	1,000	1,000
		Subtotal	$ 5,000	$ 2,341
		Cash	—	308
		Total	$ 5,000	$ 2,649

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

FES had $101 million (payable to AE Supply) and $8 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FES' available liquidity as of January 31, 2017 was as follows:

Type	**Commitment**	**Available Liquidity**
	(In millions)	
Two-year secured credit facility with FE	$ 500	$ 500
Cash	—	2
	$ 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 December 31, 2016:

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)(3)

(1) No limitations.
(2) Includes amounts which may be borrowed under the regulated companies' money pool.
(3) Pending regulatory approval, as discussed under "Outlook - FERC Matters" below.

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

As of December 31, 2016, 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. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 disclosed above are excluded from FE's calculation of total capitalization pursuant to the new exclusion referenced in (ii) above consistent with the terms of the facility.

Term Loans

On December 6, 2016, FE terminated its existing $1 billion and $200 million term loan credit agreements and entered into a new $1.2 billion five-year syndicated term loan credit agreement. The term loan contains covenants and other terms and conditions substantially similar to those of the FE revolving credit facility described above, including a consolidated debt to total capitalization ratio and minimum interest coverage ratio requirement.

The initial borrowing under the new $1.2 billion FE 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. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE's reference ratings plus the highest of (i) the administrative agent's publicly-announced "prime rate", (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE's reference ratings. Changes in FE’s reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

On February 16, 2017, FE entered into two separate $125 million three-year term loan credit agreements with Bank of America, N.A. and The Bank of Nova Scotia, respectively, the proceeds of which were used to reduce short-term debt. The terms and conditions of these new credit agreements are substantially similar to the December 6, 2016, $1.2 billion five-year syndicated term loan credit agreement.

As of December 31, 2016, 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 its term loan.

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 2016 was 0.69% per annum for the regulated companies’ money pool and 2.02% per annum for the unregulated companies’ money pool.

As discussed above, FES expects to use its new $500 million secured credit facility with FE in lieu of borrowing under the unregulated companies' money pool. In addition, a separate money pool for use by FES, its subsidiaries and FENOC is expected to be established in the first quarter of 2017 at which time those companies will no longer have access to the unregulated companies' money pool. As of January 31, 2017, FES, its subsidiaries and FENOC had no borrowings in the aggregate under the unregulated companies' money pool.

Pollution Control Revenue Bonds

In 2016, as discussed below, FG remarketed $86 million of fixed rate PCRBs and retired $12 million of variable interest rate PCRBs, which resulted in the elimination of LOCs related to $92 million of variable interest rate PCRBs that are no longer outstanding.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of January 31, 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-	Baa2	BBB+
CEI	BBB+	Baa1	A-	BBB-	Baa3	BBB+
FET	—	—	—	BB+	Baa3	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	Baa1	BBB+
MP	BBB+	A3	BBB+	—	—	—
OE	BBB+	A2	A-	BBB-	Baa1	BBB+
PN	—	—	—	BBB-	Baa2	BBB+
Penn	—	A2	A-	—	—	—
PE	BBB+	A3	BBB+	—	—	—
TE	BBB+	Baa1	A-	—	—	—
TrAIL	—	—	—	BBB-	A3	BBB+
WP	BBB+	A2	A-	—	—	—

In January 2017, Fitch initiated coverage of FE's subsidiaries and established ratings as indicated in the above table.

On February 3, 2017, Moody's upgraded the senior secured rating of WP, to A1 from A2 and the senior unsecured ratings of ME to A3 from Baa1 and PN to Baa1 from Baa2.

Debt capacity is subject to the consolidated debt to total capitalization limits in the credit facilities previously discussed. As of December 31, 2016, FE and its subsidiaries could issue additional debt of approximately $4.6 billion, or incur a $2.5 billion reduction to equity, and remain within the limitations of the financial covenants required by the credit facilities.

Changes in Cash Position

As of December 31, 2016, FirstEnergy had $199 million of cash and cash equivalents compared to $131 million of cash and cash equivalents as of December 31, 2015. As of December 31, 2016 and 2015, FirstEnergy had approximately $61 million and $82 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

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

Net cash provided from operating activities was $3,371 million during 2016, $3,447 million during 2015 and $2,713 million during 2014.

2016 compared with 2015

Cash flows from operations decreased $76 million in 2016 compared with 2015. The year over year change in cash from operations decreased due to the following:

- A $239 million increase in cash contributions to the qualified pension plan, partially offset by;
- Higher distribution deliveries and the full year impact of net rate increases implemented in 2015 at certain Utilities;
- Higher transmission revenue, reflecting recovery of incremental operating expenses and a higher rate base;
- Lower disbursements for fuel and purchased power resulting from the lower sales volumes partially offset by lower capacity revenues at CES.

2015 compared with 2014

Cash flows from operations increased $734 million in 2015 compared with 2014 due to the following:

- Distribution rate increases associated with the implementation of new rates, partially offset by a year-over-year decline in distribution deliveries;
- Higher transmission revenue and earnings, reflecting recovery of incremental operating expenses, a higher rate base and forward-looking rates at ATSI;
- Higher capacity revenues at CES, partially offset by a decline in sales volume;
- Lower disbursements for fuel and purchased power resulting from lower sales volumes; and
- Lower posted collateral; partially offset by,
- A $143 million contribution to the qualified pension plan in 2015.

Cash Flows From Financing Activities

In 2016, cash used for financing activities was $22 million compared to $279 million in 2015 and $513 million of net cash provided from financing activities in 2014. The following table summarizes new debt financing (net of any discounts), redemptions and common stock dividend payments:

	For the Years Ended December 31		
Securities Issued or Redeemed / Repaid	**2016**	**2015**	**2014**
		(In millions)	
New Issues			
Unsecured notes	$ —	$ 475	$ 2,400
PCRBs	471	339	878
FMBs	305	295	200
Term loan	1,200	200	1,050
Senior secured notes	—	2	—
	$ 1,976	$ 1,311	$ 4,528
Redemptions / Repayments			
Unsecured notes	$ (300)	$ —	$ (600)
PCRBs	(483)	(313)	(793)
FMBs	(246)	(215)	(175)
Term loan	(1,200)	(200)	—
Senior secured notes	(102)	(151)	(191)
	$ (2,331)	$ (879)	$ (1,759)
Short-term borrowings, net	$ 975	$ (91)	$ (1,605)
Common stock dividend payments	$ (611)	$ (607)	$ (604)

On May 1, 2016, JCP&L repaid $300 million of 5.625% senior unsecured notes at maturity.

On June 1 and July 1 of 2016, NG repurchased approximately $225 million and $60 million, respectively of PCRBs, which were subject to a mandatory put on such date. On August 15, 2016, NG remarketed the approximately $285 million of PCRBs secured by FMBs with a fixed interest rate of 4.375% and mandatory put dates ranging from June 1, 2022 to July 1, 2022.

On July 11, 2016, Penn issued $50 million of 4.24% FMBs due 2056. Proceeds received from the issuance of the FMBs were used: (i) to fund capital expenditures; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

On August 15, 2016, WP repaid $145 million of 5.875% FMBs at maturity. Also, on September 23, 2016, WP agreed to sell $475 million of new 3.84% FMBs due 2046 ($100 million), 4.09% FMBs due 2047 ($100 million) and 4.14% FMBs due 2047 ($275 million). On December 15, 2016, WP issued the $100 million of 3.84% FMBs due 2046. The remaining sales are expected to settle on September 15, 2017 and December 15, 2017, respectively. Proceeds to be received from the issuances of the FMBs were or are, as the case may be, expected to be used: (i) for general corporate purposes; and (ii) to repay a portion of WP's $275 million of 5.95% FMBs that mature on December 15, 2017.

On August 15, 2016, FG remarketed approximately $86 million of PCRBs secured by FMBs with fixed interest rates ranging from 4.25% to 4.50% and mandatory put dates ranging from May 1, 2021 to June 1, 2021.

On September 15, 2016, FG remarketed $100 million of PCRBs secured by FMBs with a fixed interest rate of 4.25% and a mandatory put of September 15, 2021.

On September 15 and 30, 2016, respectively, FG retired an aggregate of $12 million of PCRBs with original maturity dates in 2018 and 2029.

On October 17, 2016, PE issued $155 million of 3.89% FMBs due 2046. Proceeds received from the issuance were used: (i) to repay short-term borrowings incurred to repay PE's $100 million of 5.80% FMBs that matured on October 15, 2016; and (ii) for general corporate purposes.

Cash Flows From Investing Activities

Cash used for investing activities in 2016 principally represented cash used for property additions. The following table summarizes investing activities for 2016, 2015 and 2014:

	For the Years Ended December 31		
Cash Used for Investing Activities	**2016**	**2015**	**2014**
		(In millions)	
Property Additions:			
Regulated distribution	$ 1,063	$ 1,040	$ 855
Regulated transmission	1,101	1,020	1,446
Competitive energy services	619	588	939
Corporate / other	52	56	72
Nuclear fuel	232	190	233
Proceeds from asset sales	(15)	(20)	(394)
Investments	111	114	103
Asset removal costs	145	142	153
Other	(27)	(8)	(48)
	$ 3,281	$ 3,122	$ 3,359

2016 compared with 2015

Cash used for investing activity in 2016 increased $159 million, compared to the same period of 2015, primarily due to increases in nuclear fuel purchases and property additions. Property additions increased primarily due to higher transmission investment and CES' purchase of the remaining non-affiliated leasehold interest in Perry Unit 1. The increase in nuclear fuel was due to the scheduled Davis-Besse refueling and maintenance outage in 2016.

2015 compared with 2014

Cash used for investing activity in 2015 as compared to 2014 were impacted by lower property additions of $608 million, partially offset by a $374 million reduction in proceeds received from asset sales, as 2014 included proceeds from the sale of certain hydroelectric assets. The decline in property additions were due to the following:

- a decrease of $351 million at CES, resulting from the absence of capital investments associated with the Davis-Besse steam generators that were placed into service in May 2014,
- a decrease of $426 million at Regulated Transmission primarily relating to the timing of capital investments associated with its *Energizing the Future* investment program, partially offset by
- an increase of $185 million at Regulated Distribution relating to utility specific project investments and costs associated with the Pennsylvania smart meter program.

CONTRACTUAL OBLIGATIONS

As of December 31, 2016, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2017	2018-2019	2020-2021	Thereafter
			(In millions)		
Long-term debt[(1)]	$ 19,881	$ 1,641	$ 3,968	$ 2,063	$ 12,209
Short-term borrowings	2,675	2,675	—	—	—
Interest on long-term debt[(2)]	12,539	986	1,736	1,556	8,261
Operating leases[(3)]	1,957	125	265	216	1,351
Capital leases[(3)]	117	32	44	26	15
Fuel and purchased power[(4)]	10,438	1,368	2,180	1,629	5,261
Capital expenditures [(5)]	1,668	647	762	259	—
Pension funding	2,565	—	827	1,032	706
Total	$ 51,840	$ 7,474	$ 9,782	$ 6,781	$ 27,803

(1) Excludes unamortized discounts and premiums, fair value accounting adjustments and capital leases.
(2) Interest on variable-rate debt based on rates as of December 31, 2016.
(3) See Note 7, Leases, of the Combined Notes to Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(5) Amounts represent committed capital expenditures as of December 31, 2016.

Excluded from the table above are estimates for the cash outlays from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. Although actual amounts will be determined by future customer behavior and consumption levels, management currently estimates these cash outlays will be approximately $2.9 billion in 2017, of which $0.4 billion are expected to relate to the Utilities' contracts with FES.

The table above also excludes regulatory liabilities (see Note 15, Regulatory Matters), AROs (see Note 14, Asset Retirement Obligations), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 16, Commitments, Guarantees and Contingencies) since the amount and timing of the cash payments are uncertain. The table also excludes accumulated deferred income taxes and investment tax credits since cash payments for income taxes are determined based primarily on taxable income for each applicable fiscal year.

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.3 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy’s maximum potential assessment under these provisions would be $509 million (NG-$506 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, NG purchases insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. NG is a Member Insured of NEIL, which provides coverage for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. NG, as the Member Insured and each entity with an insurable interest, purchases policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.40 billion (NG-$1.39 billion) for replacement power costs incurred during an outage after an initial 12-week waiting period.

NG, as the Member Insured and each entity with an insurable interest, is insured under property damage insurance provided by NEIL. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. Member Insureds of NEIL pay annual premiums and are subject to retrospective premium assessments if losses exceed the accumulated funds available to the insurer. NG purchases insurance through NEIL that will pay its obligation in the event a retrospective premium call is made by NEIL, subject to the terms of the policy.

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of NG's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy’s insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could be required to make under these guarantees as of December 31, 2016, 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)	$	12
Deferred compensation arrangements(2)		559
Other(3)		10
		581
Subsidiaries' Guarantees		
Energy and Energy-Related Contracts(4)		265
FES' guarantee of nuclear decommissioning costs(5)(6)		21
FES' guarantee of FG's sale and leaseback obligations		1,647
		1,933
FE's Guarantees on Behalf of Business Ventures		
Global Holding Facility		300
Other Assurances		
Surety Bonds - Wholly Owned Subsidiaries(7)		373
Surety Bonds		22
Sale leaseback indemnity		58
LOCs(8)		12
		465
Total Guarantees and Other Assurances	$	3,279

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

(2) CES related portion is $139 million, including $53 million and $86 million at FES and FENOC, respectively.

(3) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $3 million for railcar leases, and $3 million for various leases.

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

(5) NG funded a $10 million supplemental trust in December 2016 to replace this guarantee, which will terminate in April 2017.

(6) FES provides a parental support agreement to NG of up to $400 million that may be required in the event of extraordinary circumstances. FE is working with FES to establish conditional credit support on terms and conditions to be agreed upon for the $400 million FES parental support agreement that is currently in place for the benefit of NG in the event that FES is unable to provide the necessary support to NG.

(7) Effective January 2017, FE is an indemnitor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

(8) Includes $9 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities and $3 million pledged in connection with the sale and leaseback of the Beaver Valley Unit 2 by OE.

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 FES' power portfolio exposure as of December 31, 2016, FES has posted collateral of $190 million and AE Supply has posted collateral of $4 million. The Regulated Distribution Segment has posted collateral of $3 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of December 31, 2016:

Potential Additional Collateral Obligations	**FES**	**AE Supply**	**Regulated**	**Total**
		(In millions)		
Contractual Obligations for Additional Collateral				
At Current Credit Rating	$ 7	$ 3	$ —	$ 10
Upon Further Downgrade	—	—	48	48
Surety Bonds (Collateralized Amount)[(1)]	240	25	102	367
Total Exposure from Contractual Obligations	$ 247	$ 28	$ 150	$ 425

[(1)] Effective January 2017, FE is a guarantor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2016, neither FES nor AE Supply had any collateral posted with their affiliates. Moreover, a further downgrade for either FES or AE Supply would not trigger any obligations to post any such collateral.

Other Commitments, Contingencies and Assurances

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 FirstEnergy, 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 and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $879 million as of December 31, 2016 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Upon the completion of this transaction, NG will have obtained all of the lessor equity interests at Beaver Valley Unit 2. Therefore, upon the expiration of the Beaver Valley Unit 2 leases, NG will be the sole owner of Beaver Valley Unit 2 and entitled to 100% of the unit's output. As of December 31, 2016, OE's leasehold interest was 2.60% of Beaver Valley Unit 2 and FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

On May 23, 2016, NG completed the purchase of the 3.75% lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 for $50 million. In addition, the Perry Unit 1 leases expired in accordance with their terms on May 30, 2016, resulting in NG being the sole owner of Perry Unit 1 and entitled to 100% of the unit's output.

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 10, Fair Value Measurements", of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative assets and liabilities as of December 31, 2016 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)			
Prices actively quoted[1]	$ 4	$ —	$ —	$ —	$ —	$ —	$ 4
Other external sources[2]	27	(8)	(31)	(11)	—	—	(23)
Prices based on models	(1)	—	—	—	—	—	(1)
Total[3]	$ 30	$ (8)	$ (31)	$ (11)	$ —	$ —	$ (20)

(1) Represents exchange traded New York Mercantile Exchange futures and options.

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

(3) Includes $(107) 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 as of December 31, 2016, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $29 million during the next twelve months.

Equity Price Risk

As of December 31, 2016, the FirstEnergy pension plan assets were allocated approximately as follows: 46% in equity securities, 31% in fixed income securities, 8% in absolute return strategies, 10% in real estate, 1% in private equity, and 4% in cash and short-term securities. A decline in the value of plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016. In 2017, FirstEnergy does not have a minimum required funding obligation to its qualified pension plan due to the equity contribution. See "Note 4, Pension and Other Postemployment Benefits", of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2016, FirstEnergy's pension plan assets earned approximately 8.6%, as compared to an expected return on plan assets of 7.5%.

As of December 31, 2016, FirstEnergy's OPEB plans were invested in fixed income and equity securities. In 2016 FirstEnergy's OPEB plans have earned approximately 7.0% 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 December 31, 2016, approximately 61% of the funds were invested in fixed income securities, 37% of the funds were invested in equity securities and 2% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,531 million, $925 million and $60 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2016, excluding $(2) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $93 million reduction in fair value as of December 31, 2016. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy's NDT funds or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2016, FirstEnergy contributed approximately $2 million to the NDT.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in "Note 7, Leases" of the Combined Notes to Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	**2017**	**2018**	**2019**	**2020**	**2021**	**There-after**	**Total**	**Fair Value**
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 2	$ —	$ —	$ —	$ —	$ 1,768	$ 1,770	$ 1,771
Average interest rate	8.9%	—%	—%	—%	—%	3.8%	3.8%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 1,517	$ 1,329	$ 1,035	$ 541	$ 58	$ 14,203	$ 18,683	$ 18,627
Average interest rate	6.2%	6.0%	6.9%	5.6%	4.9%	5.3%	5.53%	
Variable rate	$ 2	$ —	$ —	$ —	$ 1,200	$ —	$ 1,202	$ 1,202
Average interest rate	—%	—%	—%	—%	2.4%	—%	2.43%	

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 set in PE's plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The costs of the 2015-2017 plan are expected to be approximately $70 million, of which $43 million was incurred through December 31, 2016. 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.

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 include 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 (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L filed to participate as a respondent in that proceeding. Briefing has been completed. The oral argument was held on October 25, 2016.

On April 28, 2016, JCP&L filed tariffs with the NJBPU proposing a general rate increase associated with its distribution operations 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. The filing requested approval to increase annual operating revenues by approximately $142.1 million based upon a hybrid test year for the twelve months ending June 30, 2016. On November 30, 2016, JCP&L submitted to the ALJ a Stipulation of Settlement achieved with all the intervening parties providing for an annual $80 million distribution revenue increase, effective January 1, 2017. The ALJ filed an Initial Decision concluding that the Stipulation of Settlement should be approved, and the NJBPU approved the Stipulation of Settlement on December 12, 2016. As part of the Stipulation of Settlement the intervening parties agreed that JCP&L can accelerate the amortization of the 2012 major storm expenses (approximately $19 million annually) that are recovered through the SRC to achieve full recovery by December 31, 2019. On November 23, 2016, JCP&L filed an Amendment to its January 15, 2016 SRC Filing with the NJBPU, requesting that JCP&L be able to accelerate the amortization of the 2012 major storm expenses as agreed to in the Stipulation of Settlement, and a Stipulation of Settlement with NJBPU Staff and the Division of Rate Counsel regarding the SRC Filing was filed on December 27, 2016. The NJBPU approved this Stipulation of Settlement at the January 25, 2017 public meeting.

OHIO

The Ohio Companies currently operate under an ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO's Opinions and Orders issued on March 31, 2016 and 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 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 approximately $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 the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs, an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016), a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045, and contributions, totaling $51 million, to fund energy conservation programs, economic development and job retention in the Ohio Companies' service territory, and a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers, and to establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On April 29, 2016 and May 2, 2016, several parties, including the Ohio Companies, filed applications for rehearing on the Ohio Companies' ESP IV with the PUCO. On September 6, 2016, while the applications for rehearing were still pending before the PUCO, the OCC and NOAC filed a notice of appeal with the Ohio Supreme Court appealing various PUCO and Attorney Examiner Entries on the parties' applications for rehearing. On September 16, 2016, the Ohio Companies intervened and filed a motion to dismiss the appeal. The PUCO resolved such applications for rehearing in the October 12, 2016 Opinion and Order. The OCC and NOAC appeal remains pending before the Ohio Supreme Court.

On November 10, 2016 and November 14, 2016, several parties, including the Ohio Companies, filed additional applications for rehearing on 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 were required to implement energy efficiency programs that achieved a total annual energy savings of 1,990 GWHs and total peak demand reduction of 486 MWs in 2015. On May 12, 2016, the Ohio Companies filed their Energy Efficiency and Peak Demand Reduction Program Status Report indicating compliance with their 2015 statutory benchmarks. In 2016, the Ohio Companies estimated the annual energy savings target and peak demand reduction target will be comparable to the 2015 targets due to the energy efficiency requirements under SB310, which amended ORC 4928.66 to freeze the energy efficiency and peak demand reduction benchmarks for 2015 and 2016. 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.

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 2015 and 2016 that remain at the 2014 level. 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. The matter is not yet scheduled for oral argument.

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. The matter remains pending before the PUCO.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3-, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

Following the expiration of the current DSPs, the Pennsylvania Companies will operate under new 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 new 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. In addition, the new DSPs include modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans were effective through May 31, 2016. Total Phase II costs of these plans were $174 million and are recoverable through the Pennsylvania Companies' reconcilable EE&C riders. 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- $88.34 million; PN- $56.74 million; Penn- $56.35 million; and ME- $43.44 million. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. On June 9, 2016, the PPUC approved the Pennsylvania Companies' DSIC riders to be effective July 1, 2016, subject to hearings and refund or reallocation among customers. The four proceedings were consolidated by the ALJ. On January 19, 2017, in the PPUC's order approving the Pennsylvania Companies' general rate cases, discussed below, the PPUC referred the issue of whether ADIT should be included in DSIC calculations to the consolidated DSIC proceeding. On February 2, 2017, the parties to the consolidated DSIC proceeding submitted a Joint Settlement to the ALJ to resolve issues referred to by the ALJ in its June 9, 2016 Order, subject to PPUC approval, and would not result in any refund or reallocation among customers. The ADIT issue will be considered separately from the issues resolved in the Joint Settlement Petition of February 2, 2017, and is the sole issue to be litigated in the consolidated DSIC proceeding through a procedural schedule to be determined by the ALJ.

On April 28, 2016, each of the Pennsylvania Companies filed tariffs with the PPUC proposing general rate increases associated with their distribution operations to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements. The filings requested approval to increase annual operating revenues by approximately $140.2 million at ME, $158.8 million at PN, $42.0 million at Penn, and $98.2 million at WP, based upon fully projected future test years for the twelve months ending December 31, 2017 at each of the Pennsylvania Companies. As a result of the enactment of Act 40 of 2016 that terminated the practice of making a CTA when calculating a utility's federal income taxes for ratemaking purposes, the Pennsylvania Companies submitted supplemental testimony on July 7, 2016, that quantified the value of the elimination of the CTA and outlined their plan for investing 50 percent of that amount in rate base eligible equipment as required by the new law. Formal settlement agreements for each of the Pennsylvania Companies were filed on October 14, 2016, which proposed increases in annual operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP. One item related to the calculation of DSIC rates was reserved for briefing, with briefs filed by two parties. On November 21, 2016, the ALJ issued a Recommended Decision recommending approval of the settlement agreements and dismissal of the one issue reserved for briefing. Exceptions to that Recommended Decision were filed by one party on December 1, 2016, and reply exceptions were filed by the Pennsylvania Companies on December 8, 2016. On January 19, 2017, the PPUC issued an order approving the settlements and referring the reserved issue to the Pennsylvania Companies' consolidated DSIC proceeding. On February 3, 2017, one party filed a Petition for Reconsideration or Clarification relating to the limited issue of the scope of the record to be transferred to the DSIC proceeding, discussed above. The outcome of this request will not affect the new rates which took effect on January 27, 2017.

WEST VIRGINIA

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

On March 31, 2016, MP and PE filed with the WVPSC seeking approval of their Phase II energy efficiency program including three MP and PE energy efficiency programs to meet their Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, as agreed to by MP and PE, and approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of the 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. A unanimous settlement was reached by the parties on all issues and presented to the WVPSC on August 18, 2016. An order approving the settlement in full without modification was issued by the WVPSC on September 23, 2016. The Phase II program began initial implementation in November 2016.

The Staff of the WVPSC and the Consumer Advocate Division filed a Show Cause petition on August 5, 2016, requesting that the WVPSC order MP and PE to file and implement RFPs for all future capacity and energy requirements above 100 MWs and that they comply with an RFP settlement provision from the Harrison power station acquisition. MP and PE filed a timely response to the petition arguing for dismissal on September 7, 2016. On October 17, 2016, the WVPSC denied the petition filed by the Staff of the WVPSC and the Consumer Advocate Division and dismissed the case.

On August 16, 2016, MP and PE filed their annual ENEC case proposing an annual increase in rates of approximately $65 million effective January 1, 2017, which is a 4.7% increase over existing rates. The increase is comprised of a $119 million under-recovered balance as of June 30, 2016, and a projected $54 million over-recovery for the 2017 rate effective period. The parties reached a unanimous settlement providing for a $25 million increase beginning January 1, 2017 and keeping ENEC rates at the same level for a two year period. The settlement was presented to the WVPSC at a hearing on November 9, 2016. On December 9, 2016, the WVPSC approved the settlement as submitted.

On August 22, 2016, MP and PE filed an application for approval of a modernization and improvement plan for coal-fired boilers at electric power plants and cost-recovery surcharge proposing an approximate $6.9 million annual increase in rates to be effective May 1, 2017, which is a 0.5% increase over existing rates. The filing is in response to recent legislation by the West Virginia Legislature permitting accelerated recovery of costs related to modernizing and improving coal-fired boilers, including costs related to meeting environmental requirements and reducing emissions. The filing was supplemented on September 28, 2016, to add two additional projects, resulting in an approximate $7.4 million annual increase in rates. The Staff of the WVPSC filed a motion to dismiss the case arguing the new statute was not meant to recover these types of projects, but the WVPSC set the case for hearing for February 21-23, 2017. As part of the annual ENEC settlement described above, the parties agreed that MP and PE will increase ENEC rates to provide for a return of and on MATS/CSPR capital costs incurred during 2016-2017. Accordingly, MP and PE withdrew this case as part of the ENEC approval.

On December 30, 2015, MP 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 finding that IRPs are informational and that it must not approve or disapprove the IRP. MP issued a RFP to address its generation shortfall identified in the IRP on December 16, 2016 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. MP expects to execute definitive agreements with selected respondent(s) and file the appropriate applications with the WVPSC and FERC by March 15, 2017.

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 its subsidiaries, AE Supply, FENOC, ATSI 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.

On January 27, 2016, certain parties filed a complaint with FERC against FES and the Ohio Companies requesting FERC review the ESP IV PPA under Section 205 of the FPA. On April 27, 2016, FERC issued an order granting the complaint, prohibiting any transactions under the ESP IV PPA pending authorization by FERC, and directing FES to submit the ESP IV PPA for FERC review if the parties desired to transact under the agreement. FES and the Ohio Companies did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA. FES and the Ohio Companies subsequently advised FERC of this course of action. On January 19, 2017, FERC issued an order accepting compliance filings by FES, its subsidiaries, and the Ohio Companies updating their respective market-based rate tariffs to clarify that affiliate sales restrictions under the tariffs apply to the ESP IV PPA, and also that the ESP IV PPA does not affect certain other waivers of its affiliate restrictions rules FERC previously granted these entities.

On May 2, 2016, the Ohio Companies filed an Application for Rehearing with the PUCO that included a modified Rider RRS proposal that did not involve a FERC-jurisdictional PPA. Several parties subsequently filed protests and comments with FERC alleging, among other things, that the modified Rider RRS constituted a "virtual PPA". FERC rejected these protests in its January 19, 2017 order accepting the updated market-based rate tariffs of FES, its subsidiaries, and the Ohio Companies discussed below.

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. The PJM TOs responded to the protesting parties' various pleadings and motions. 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. On July 15, 2016, the MISO TOs filed an appeal of FERC's orders with the Sixth Circuit. On November 16, 2016, the Sixth Circuit granted FirstEnergy's intervention on behalf of ATSI, the Ohio Companies, and PP, and a procedural schedule has been established. 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.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. In February and August 2016, respectively, FERC and the PPUC granted the authorization for PN and ME to contribute their transmission assets to MAIT at book value, together with the approval of related intercompany agreements, including MAIT's participation in FirstEnergy's regulated companies' money pool. FirstEnergy subsequently withdrew its request for authorization before the NJBPU to also transfer JCP&L's transmission assets to MAIT.

On October 28, 2016, MAIT and PJM submitted joint applications to FERC requesting authorization for (i) PJM to update its Tariff and other agreements to reflect the withdrawal of ME and PN as TOs, and (ii) MAIT to become a participating PJM TO. FERC approval would authorize MAIT to be a PJM TO, and would permit PJM to implement MAIT's formula rate on MAIT's behalf. On January 26, 2017, FERC issued an order granting the requested authorization and MAIT now owns and operates the transmission assets of ME and PN. On January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and asset contributions.

On October 14 and 28, 2016, MAIT submitted applications to FERC requesting authorization to issue equity, short-term debt, and long-term debt. On December 8, 2016, FERC issued an order authorizing the application to issue equity as requested. MAIT is expected to issue short-term debt and participate in the FirstEnergy regulated companies' money pool for working capital, to fund day-to-day operations, and for other general corporate purposes. Over the long-term, MAIT is expected to issue long-term debt to support capital investment and to establish an actual capital structure for ratemaking purposes. On February 3, 2017, MAIT amended its debt authorization application to provide additional information regarding recovery of its investment and debt costs. MAIT requested an order from FERC on the debt authorization by February 28, 2017. FERC's order remains pending.

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. On November 30, 2016, 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. MAIT filed a response to the protests on December 12, 2016. On December 28, 2016, FERC Staff issued a deficiency letter with respect to the PJM-related application, which also requested additional information regarding MAIT's proposed formula rate. As a result of the deficiency letter, FERC's order on the formula rate remains pending. MAIT responded to FERC Staff's request on January 10, 2017, and requested that FERC issue an order approving the formula rate immediately after consummation of the transaction, which occurred on January 31, 2017. On February 15, 2017, MAIT filed a further answer to certain protesting parties' comments on its January 10th deficiency letter response.

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. On November 18, 2016, 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 December 5, 2016, JCP&L filed a response to the protest. On December 28, 2016, FERC Staff issued a deficiency letter requesting additional information regarding JCP&L's proposed transmission rate. As a result of the deficiency letter, FERC's order on the rate remains pending. JCP&L responded to FERC Staff's request on January 10, 2017, and requested that FERC issue an order approving the formula rate effective January 1, 2017. On February 15, 2017, JCP&L filed a further answer to certain protesting parties' comments on its January 10th deficiency letter response.

Competitive Generation Asset Sale

On February 17, 2017, AE Supply and AGC submitted filings with FERC for authorization to sell four natural gas generating plants and an undivided ownership interest in Bath County to Aspen for approximately $925 million, in an all cash transaction. The four natural gas plants are: Springdale Generating Facility (638 MWs), Chambersburg Generating Facility (88 MWs), Gans Generating Facility (88 MWs), and Hunlock Creek (45 MWs). The 713 MW ownership interest in Bath County represents AE Supply's indirect ownership interest in the power station. The FERC applications include a request for authorization to transfer the hydroelectric license under Part I of the FPA, and a request for authorization to transfer the FERC-jurisdictional facilities associated with the hydroelectric projects under Part II of the FPA. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once regulatory approval is obtained. The VSCC also must approve the sale of the Bath County Hydro interest. The parties expect to close the transaction in the third quarter of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents. See "Executive Summary" above for additional information regarding the transaction.

California Claims Litigation

Since 2002, AE Supply has been involved in litigation and claims based on its power sales to the California Energy Resource Scheduling division of the CDWR during 2001-2003. This litigation and claims are related to litigation and claims advanced by the California Attorney General and certain California utilities regarding alleged market manipulation of the wholesale energy markets in California during the 2000-2001 period. AE Supply negotiated a settlement with the California Attorney General and the California utilities and, on August 24, 2016, filed the settlement agreement for FERC approval. The settlement calls for AE Supply to pay, without admission of any liability, $3.6 million in settlement in principle of all remaining claims that are based on AE Supply's power sales in the western energy markets during the 2001-2003 time period. On October 27, 2016 FERC approved this settlement, and AE Supply paid the settlement shortly thereafter.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. 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 settlement proceedings and a hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. On January 19, 2017, FERC issued an order accepting the initial decision in part and denying it in part. Relying on its revised ROE methodology described in FERC Opinion No. 531, FERC reduced the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017. Additionally, FERC allowed recovery of costs related to land acquisitions and dispositions and legal expenses, but disallowed certain costs related to advertising and outreach. PATH filed a request for rehearing with FERC on February 20, 2017, seeking recovery of the advertising and outreach costs and requesting that the ROE be reset to 10.4%.

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. 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 of Delaware's CAA Section 126 petition by six months to April 7, 2017. 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. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

MATS imposes 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. FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $286 million has been spent through December 31, 2016 ($125 million at CES and $161 million at Regulated Distribution).

On August 3, 2015, FG, a 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. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG’s further performance. 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 liability hearing from November 28, 2016, through December 9, 2016, and, if necessary, a damages hearing is scheduled to begin on May 8, 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearing proceedings, which are scheduled to conclude February 24, 2017. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG’s performance under the contract is therefore excused. FG intends to vigorously assert its position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. Refer to the

"Executive Summary" above for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS who 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 Plant. 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. FG intends to vigorously assert its position in this arbitration proceeding. 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. Refer to the "Executive Summary" above for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced in the above arbitration proceedings, FG paid approximately $70 million in the aggregate in liquidated damages to settle delivery shortfalls in 2014 related to its deactivated plants, which approximated full liquidated damages under the agreements for such year related to the plant deactivations. Liquidated damages for the period 2015-2025 remain in dispute under both coal transportation agreements.

As to a specific coal supply agreement, AE Supply asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, the coal supplier commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. AE Supply has filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are approximately 5.5 million tons remaining under the contract for delivery. At this time, AE Supply cannot estimate the loss or range of loss regarding the ongoing litigation with respect to this agreement.

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. Depending on the outcome 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 greenhouse gas 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 are effective on November 4, 2016. It remains unclear whether and how the results of the 2016 United States election could impact the regulation of GHG emissions at the federal and state level. 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 will 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. 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 December 31, 2016 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 $137 million have been accrued through December 31, 2016. Included in the total are accrued liabilities of approximately $89 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 loss cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2016, FirstEnergy had approximately $2.5 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 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. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As FES no longer maintains investment grade credit ratings from either S&P or Moody’s, NG funded a $10 million supplemental trust in 2016 in lieu of the FES parental guarantee that would be required to support the decommissioning of the spent fuel storage facilities. The termination of the FES parental guarantee is subject to NRC review. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantees, as appropriate.

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. In addition to the $500 million credit facility with FE discussed above, FE is working with FES to establish conditional credit support on terms and conditions to be agreed upon for the $400 million FES parental support agreement that is currently in place for the benefit of NG in the event that FES is unable to provide the necessary support to NG.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 15, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. FirstEnergy's accounting policies require significant judgment regarding estimates and assumptions underlying the amounts included in the financial statements. Additional information regarding the application of accounting policies is included in the Combined Notes to Consolidated Financial Statements.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class. See Note 1, Organization and Basis of Presentation for additional details.

Regulatory Accounting

FirstEnergy's regulated distribution and regulated transmission segments are subject to regulations that set the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to be recovered. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. See Note 15, Regulatory Matters for additional information.

FirstEnergy reviews the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Similarly, FirstEnergy records regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. If recovery of a regulatory asset is no longer probable, FirstEnergy will write off that regulatory asset as a charge against earnings.

Pension and OPEB Accounting

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels.

FirstEnergy provides some non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits and/or subsidies to purchase health insurance, which include certain employee contributions, deductibles and co-payments, may also be available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016. The independent fiduciary representing the pension plan with respect to the equity contribution fully liquidated the FE common stock by January 31, 2017.

FirstEnergy recognizes a pension and OPEB mark-to-market adjustment for the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2016, 2015, and 2014 were $194 million ($147 million net of amounts capitalized), $369 million ($242 million net of amounts capitalized), and $1,243 million ($835 million net of amounts capitalized), respectively.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pension were 4.25%, 4.50% and 4.25% as of December 31, 2016, 2015 and 2014, respectively. The assumed discount rates for OPEB were 4.00%, 4.25% and 4.00% as of December 31, 2016, 2015 and 2014, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2016, FirstEnergy's qualified pension and OPEB plan assets experienced earnings of $472 million or 8.2% compared to losses of $(172) million, or (2.7)% in 2015 and earnings of $387 million, or 6.2% in 2014 and assumed a 7.50% rate of return on plan assets in 2016 and a 7.75% expected rate of return in 2015 and 2014 which generated $429 million, $476 million and $496 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement. The expected return on plan assets for 2017 is 7.5%.

During 2016, the Society of Actuaries released its updated mortality improvement scale for pension plans, MP-2016, incorporating three additional years of SSA data on U.S. population mortality. MP-2016 incorporates SSA mortality data from 2012 to 2014 and a slight modification of two input values designed to improve the model's year-over-year stability. The updated improvement scale indicates a slight decline in life expectancy as a result of the slower average rate of mortality improvement. Due to the additional years of data on population mortality, the RP2014 mortality table with the projection scale MP-2016 was utilized to determine the 2016 benefit cost and obligation as of December 31, 2016 for the FirstEnergy pension and OPEB plans.The impact of using the projection scale MP-2016 resulted in a decrease in the projected benefit obligation of $141 million and $8 million for the pension and OPEB plans, respectively, and was included in the 2016 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.25% for pension, 4.00% for OPEB and an estimated return on assets of 7.5%, FirstEnergy expects its 2017 pre-tax net periodic benefit cost (including amounts capitalized) to be approximately $78 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2017). The following table reflects the portion of pension and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2016.

Postemployment Benefits Expense (Credits)	**2016**	**2015**	**2014**
		(In millions)	
Pension	$ 277	$ 316	$ 939
OPEB	(40)	(61)	(101)
Total	$ 237	$ 255	$ 838

Health care cost trends continue to increase and will affect future OPEB costs. The 2016 composite health care trend rate assumptions were approximately 6.0-5.5%, compared to 6.0-5.5% in 2015, gradually decreasing to 4.5% in later years. In determining FirstEnergy's trend rate assumptions, included are the specific provisions of FirstEnergy's health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy's health care plans, and projections of future medical trend rates. The effects on 2017 pension and OPEB net periodic benefit costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

Assumption	**Adverse Change**	**Pension**	**OPEB**	**Total**
			(In millions)	
Discount rate	Decrease by .25%	288	19	$ 307
Long-term return on assets	Decrease by .25%	15	1	$ 16
Health care trend rate	Increase by 1.0%	N/A	22	$ 22

See Note 4, Pension and Other Postemployment Benefits for additional information

Long-Lived Assets

FirstEnergy evaluates long-lived assets classified as held and used for impairment when events or changes in circumstances indicate the carrying value of the long-lived assets may not be recoverable. First, the estimated undiscounted future cash flows attributable to the assets is compared with the carrying value of the assets. If the carrying value is greater than the undiscounted future cash flows, an impairment charge is recognized equal to the amount the carrying value of the assets exceeds its estimated fair value. See Note 1, Organization and Basis of Presentation.

See Note 2, Asset Impairments for impairments recognized during 2016 and 2015.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2016, are described further in "Note 14, Asset Retirement Obligations".

Income Taxes

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

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. See Note 6, Taxes for additional information.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50%) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value or bypasses the qualitative assessment, then the two-step quantitative goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

As of July 31, 2016, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units' goodwill, assessing economic, industry and market considerations in addition to the reporting units' overall financial performance. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary.

See Note 2, Asset Impairments for further discussion of CES goodwill impairment charge recognized during 2016.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers". Subsequent accounting standards updates have been issued which amend and/or clarify the application of ASU 2014-09. The core principle of the new guidance is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. More detailed disclosures will also be required to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, the new revenue recognition guidance will be effective for annual and interim reporting periods beginning after December 15, 2017. Earlier adoption is permitted for annual and interim reporting periods beginning after December 15, 2016. FirstEnergy will not early adopt the standards. The standards shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy has evaluated a significant portion of its revenues and preliminarily expects limited impacts to current revenue recognition practices, dependent on the resolution of industry issues including accounting for contributions in aid of construction and the ability to recognize revenue for contracts where collectibility is in question. FirstEnergy continues to assess the remainder of its revenue streams and the impact on its financial statements and disclosures as well as which transition method it will select to adopt the guidance.

On August 27, 2014, the FASB issued ASU 2014-15, "Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." In connection with preparing financial statements for each annual and interim reporting period, the ASU requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Disclosures are required when management identifies conditions or events that raise substantial doubt. The new requirements were effective for the annual period ended December 31, 2016.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities", which primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption for certain provisions can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)", which will require organizations that lease assets with lease terms of more than twelve 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. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In March of 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting", which simplifies several aspects of the accounting for employee share-based payment. The new guidance will require all income tax effects of awards to be recognized in the income statement when the awards vest or are settled. It also will not require liability accounting when an employer repurchases more of an employee’s shares for tax withholding purposes. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. Upon adoption, January 1, 2017, FirstEnergy elected to account for forfeitures as they occur. The adoption of the ASU did not have a material impact on FirstEnergy’s financial statements.

In June 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments”, which removes all recognition thresholds and will require companies to recognize an allowance for credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost that the company expects to collect over the instrument’s contractual life. The ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted for fiscal years beginning after December 15, 2018. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments". 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. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted for all entities. FirstEnergy expects to adopt this ASU in 2017 and does not expect this ASU to have a material effect on its financial statements.

In October 2016, the FASB issued ASU 2016-16, " Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory". ASU 2016-16 eliminates the exception for all intra-entity sales of assets other than inventory, which allows companies to defer the tax effects of intra-entity asset transfers. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller’s tax jurisdiction when the intra-entity transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. Any deferred tax asset that arises in the buyer’s jurisdiction would also be recognized at the time of the transfer. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted and the modified retrospective approach will be required for transition to the new guidance, with a cumulative-effect adjustment recorded in retained earnings as of the beginning of the period of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash" that will require entities to show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. As a result, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statement of cash flows. When cash, cash equivalents, restricted cash and restricted cash equivalents are presented in more than one line item on the balance sheet, the new guidance requires a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2019. Early adoption in an interim period is permitted, but any adjustments must be reflected as of the beginning of the fiscal year that includes that interim period. FirstEnergy does not expect this ASU to have a material effect on its financial statements.

Additionally, during 2016, the FASB issued the following ASUs:

- ASU 2016-05, “Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships,”
- ASU 2016-06, “Contingent Put and Call Options in Debt Instruments (a consensus of the FASB Emerging Issues Task Force),"
- ASU 2016-07, “Simplifying the Transition to the Equity Method of Accounting," and
- ASU 2016-17, “Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control.”

FirstEnergy does not expect these ASUs to have a material effect on its financial statements

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A relating to market risk is set forth in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORT

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2016 consolidated financial statements as stated in their audit report included herein. As discussed in Note 1 to the consolidated financial statements, FirstEnergy Corp. is engaged in a strategic review of its competitive operations and its wholly-owned subsidiary, FirstEnergy Solutions Corp. (FES), is facing challenging market conditions impacting FES' liquidity.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2016.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income (loss), comprehensive income (loss), common stockholders' equity, and of cash flows, present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, FirstEnergy Corp. is engaged in a strategic review of its competitive operations and its wholly-owned subsidiary, FirstEnergy Solutions Corp. (FES), is facing challenging market conditions impacting FES' liquidity.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Cleveland, Ohio
February 21, 2017

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(In millions)	For the Years Ended December 31 2016	2015	2014
REVENUES:			
Regulated Distribution	$ 9,629	$ 9,625	$ 9,102
Regulated Transmission	1,151	1,011	769
Unregulated businesses	3,782	4,390	5,178
Total revenues*	14,562	15,026	15,049
OPERATING EXPENSES:			
Fuel	1,666	1,855	2,280
Purchased power	3,813	4,318	4,716
Other operating expenses	3,858	3,749	3,962
Pension and OPEB mark-to-market adjustment	147	242	835
Provision for depreciation	1,313	1,282	1,220
Amortization of regulatory assets, net	320	268	12
General taxes	1,042	978	962
Impairment of assets (Note 2)	10,665	42	—
Total operating expenses	22,824	12,734	13,987
OPERATING INCOME (LOSS)	(8,262)	2,292	1,062
OTHER INCOME (EXPENSE):			
Investment income (loss)	84	(22)	72
Impairment of equity method investment (Note 2)	—	(362)	—
Interest expense	(1,157)	(1,132)	(1,081)
Capitalized financing costs	103	117	118
Total other expense	(970)	(1,399)	(891)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(9,232)	893	171
INCOME TAXES (BENEFITS)	(3,055)	315	(42)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(6,177)	578	213
Discontinued operations (net of income taxes of $69) (Note 20)	—	—	86
NET INCOME (LOSS)	$ (6,177)	$ 578	$ 299
EARNINGS (LOSS) PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ (14.49)	$ 1.37	$ 0.51
Basic - Discontinued Operations (Note 20)	—	—	0.20
Basic - Net Income (Loss)	$ (14.49)	$ 1.37	$ 0.71
Diluted - Continuing Operations	$ (14.49)	$ 1.37	$ 0.51
Diluted - Discontinued Operations (Note 20)	—	—	0.20
Diluted - Net Income (Loss)	$ (14.49)	$ 1.37	$ 0.71
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	426	422	420
Diluted	426	424	421
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.44	$ 1.44	$ 1.44

* Includes excise tax collections of $406 million, $416 million and $420 million in 2016, 2015 and 2014, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the Years Ended December 31		
(In millions)	2016	2015	2014
NET INCOME (LOSS)	$ (6,177)	$ 578	$ 299
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(59)	(116)	(76)
Amortized losses (gains) on derivative hedges	8	5	(2)
Change in unrealized gain on available-for-sale securities	55	(11)	26
Other comprehensive income (loss)	4	(122)	(52)
Income taxes (benefits) on other comprehensive income (loss)	1	(47)	(14)
Other comprehensive income (loss), net of tax	3	(75)	(38)
COMPREHENSIVE INCOME (LOSS)	$ (6,174)	$ 503	$ 261

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 199	$ 131
Receivables-		
Customers, net of allowance for uncollectible accounts of $53 in 2016 and $69 in 2015	1,440	1,415
Other, net of allowance for uncollectible accounts of $1 in 2016 and $5 in 2015	175	180
Materials and supplies, at average cost	564	785
Prepaid taxes	98	135
Derivatives	140	157
Collateral	176	70
Other	158	167
	2,950	3,040
PROPERTY, PLANT AND EQUIPMENT:		
In service	43,767	49,952
Less — Accumulated provision for depreciation	15,731	15,160
	28,036	34,792
Construction work in progress	1,351	2,422
	29,387	37,214
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,514	2,282
Other	512	506
	3,026	2,788
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	6,418
Regulatory assets	1,014	1,348
Other	1,153	1,286
	7,785	9,052
	$ 43,148	$ 52,094
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,685	$ 1,166
Short-term borrowings	2,675	1,708
Accounts payable	1,043	1,075
Accrued taxes	580	519
Accrued compensation and benefits	363	334
Derivatives	78	106
Collateral	42	52
Other	660	642
	7,126	5,602
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 442,344,218 and 423,560,397 shares outstanding as of December 31, 2016 and December 31, 2015, respectively	44	42
Other paid-in capital	10,555	9,952
Accumulated other comprehensive income	174	171
Retained earnings (Accumulated deficit)	(4,532)	2,256
Total common stockholders' equity	6,241	12,421
Noncontrolling interest	—	1
Total equity	6,241	12,422
Long-term debt and other long-term obligations	18,192	19,099
	24,433	31,521
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	3,765	6,773
Retirement benefits	3,719	4,245
Asset retirement obligations	1,482	1,410
Deferred gain on sale and leaseback transaction	757	791
Adverse power contract liability	162	197
Other	1,704	1,555
	11,589	14,971
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16)		
	$ 43,148	$ 52,094

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Common Stock		Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings (Accumulated Deficit)
(In millions, except share amounts)	**Number of Shares**	**Par Value**			
Balance, January 1, 2014	418,628,559	$ 42	$ 9,776	$ 284	$ 2,590
Net income					299
Amortized gains on derivative hedges, net of $1 million of income tax benefits				(1)	
Change in unrealized gain on investments, net of $10 million of income taxes				16	
Pension and OPEB, net of $23 million of income tax benefits (Note 4)				(53)	
Stock-based compensation			20		
Cash dividends declared on common stock					(604)
Stock Investment Plan and certain share-based benefit plans	2,474,011		51		
Balance, December 31, 2014	421,102,570	42	9,847	246	2,285
Net income					578
Amortized gains on derivative hedges, net of $1 million of income taxes				4	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(7)	
Pension and OPEB, net of $44 million of income tax benefits (Note 4)				(72)	
Stock-based compensation			45		
Cash dividends declared on common stock					(607)
Stock Investment Plan and certain share-based benefit plans	2,457,827		60		
Balance, December 31, 2015	423,560,397	42	9,952	171	2,256
Net loss					(6,177)
Amortized gains on derivative hedges, net of $3 million of income taxes				5	
Change in unrealized gain on investments, net of $21 million of income taxes				34	
Pension and OPEB, net of $23 million of income tax benefits (Note 4)				(36)	
Stock-based compensation			49		
Cash dividends declared on common stock					(611)
Stock Investment Plan and certain share-based benefit plans	2,685,946		56		
Stock issuance (Note 12)	16,097,875	2	498		
Balance, December 31, 2016	442,344,218	$ 44	$ 10,555	$ 174	$ (4,532)

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31		
(In millions)	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$ (6,177)	$ 578	$ 299
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	1,997	1,922	1,592
Impairment of assets	10,665	42	—
Investment impairment, including equity method investments	21	464	37
Pension and OPEB mark-to-market adjustment	147	242	835
Deferred income taxes and investment tax credits, net	(3,063)	284	162
Deferred costs on sale leaseback transaction, net	49	48	48
Deferred purchased power and fuel costs	(30)	(105)	(115)
Asset removal costs charged to income	54	55	28
Retirement benefits	64	(20)	(53)
Commodity derivative transactions, net (Note 11)	9	(73)	64
Pension trust contributions	(382)	(143)	—
Gain on sale of investment securities held in trusts	(50)	(23)	(64)
Lease payments on sale and leaseback transaction	(120)	(131)	(137)
Income from discontinued operations (Note 20)	—	—	(86)
Changes in current assets and liabilities-			
Receivables	(11)	184	139
Materials and supplies	41	(15)	(65)
Prepayments and other current assets	27	(10)	126
Accounts payable	(37)	(243)	42
Accrued taxes	61	29	(165)
Accrued compensation and benefits	29	5	(22)
Other current liabilities	56	69	54
Cash collateral, net	(116)	140	(54)
Other	137	148	48
Net cash provided from operating activities	3,371	3,447	2,713
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,976	1,311	4,528
Short-term borrowings, net	975	—	—
Redemptions and Repayments-			
Long-term debt	(2,331)	(879)	(1,759)
Short-term borrowings, net	—	(91)	(1,605)
Common stock dividend payments	(611)	(607)	(604)
Other	(31)	(13)	(47)
Net cash (used for) provided from financing activities	(22)	(279)	513
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,835)	(2,704)	(3,312)
Nuclear fuel	(232)	(190)	(233)
Proceeds from asset sales	15	20	394
Sales of investment securities held in trusts	1,678	1,534	2,133
Purchases of investment securities held in trusts	(1,789)	(1,648)	(2,236)
Asset removal costs	(145)	(142)	(153)
Other	27	8	48
Net cash used for investing activities	(3,281)	(3,122)	(3,359)
Net change in cash and cash equivalents	68	46	(133)
Cash and cash equivalents at beginning of period	131	85	218
Cash and cash equivalents at end of period	$ 199	$ 131	$ 85
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: stock contribution to pension plan	$ 500	$ —	$ —
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$ 1,050	$ 1,028	$ 931
Income taxes (received), net of refunds	$ (16)	$ 37	$ (103)

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

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

FE was 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 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 MWs of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,000 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, and purchases the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs. FES complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NRC and applicable state regulatory authorities.

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

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

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. 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 prices from the 2019/2020 PJM Base Residual Auction in May of 2016 as well as the current forward pricing and the long-term fundamental view on energy and capacity prices, which resulted in a non-cash pre-tax impairment charge of $800 million ($23 million at FES) recognized in the second quarter of 2016 representing the total amount of goodwill at CES.

As part of a continual process to evaluate its overall generation business, on July 22, 2016, FirstEnergy announced its intent to exit the 136 MW Bay Shore Unit 1 generating station by October 2020 and to deactivate Units 1-4 of the W.H. Sammis generating station totaling 720 MWs by May 2020, resulting in a $647 million ($517 million at FES) non-cash pre-tax impairment charge in the second quarter of 2016. Furthermore, in November of 2016, FirstEnergy announced that it had begun a strategic review of its competitive operations as it transitions to a fully regulated utility 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 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 Bath County (1,572 MWs of combined capacity) for an all-cash purchase price of $925 million, subject to customary and other closing conditions as further discussed in Note 22, Subsequent Events, including 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. Additionally, in connection with MP's RFP seeking additional generation capacity, AE Supply offered the Pleasants power station (1,300 MWs) for approximately $195 million.

Although FirstEnergy is targeting mid-2018 to exit from competitive operations, the options for the remaining portion of CES' generation 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,
- Additional asset sales and/or plant deactivations,
- Restructuring FES debt with its creditors, and/or
- Seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

Furthermore, adverse outcomes in previously disclosed disputes regarding long-term coal transportation contracts and/or the inability to extend or refinance debt maturities at FES subsidiaries, could accelerate management's targeted timeline and limit its options to fully exit competitive operations to either restructuring debt with its creditors or seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

As part of assessing the viability of strategic alternatives, FirstEnergy determined that the carrying value of long-lived assets of the competitive business were not recoverable, specifically given FirstEnergy's target to implement its exit from competitive operations by mid-2018, significantly before the end of the original useful lives, and the anticipated cash flows over this shortened period. As a result, CES recorded a non-cash pre-tax impairment charge of $9,218 million ($8,082 million at FES) in the fourth quarter of 2016 to reduce the carrying value of certain assets to their estimated fair value, including long-lived assets such as generating plants and nuclear fuel, as well as other assets such as materials and supplies.

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 sale of the AE Supply natural gas generating plants and AGC's interest in Bath County and, if accepted in the MP RFP process as the winning bidder, the transfer of the Pleasants Power station to MP, the size and generation capacity of CES' current portfolio will reduce to approximately 10,000 MWs 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 that have lowered the value of the business. 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 collateral requirements that otherwise would reduce available liquidity. A lack of viable alternative strategies for its competitive portfolio has and would further stress the financial condition of FES. 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 credit facility with FE, in lieu of access to the unregulated money pool, all of which is available as of January 31, 2017, its current credit rating and the current forward wholesale pricing environment are a significant challenge to FES. Furthermore, a lack of viable alternative strategies for its competitive portfolio would further stress the liquidity and financial condition of FES.

As previously disclosed, FES has $130 million of debt maturities that need to be refinanced in 2017 (and $515 million of maturing debt in 2018 beginning in the second quarter). Based on its current senior unsecured debt rating and current capital structure, reflecting the impact of the impairment charges discussed above, as well as the forecasted decline in wholesale forward market prices over the next few years, these debt maturities will be difficult to refinance, even on a secured basis, which would further stress FES' anticipated liquidity. 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 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 may similarly 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 legislative efforts to explore a regulatory solution, these obligations and their impact on liquidity raise substantial doubt about FES' ability to meet its obligations as they come due over the next twelve months and, as such, its ability to continue as a going concern.

ACCOUNTING FOR THE EFFECTS OF REGULATION

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

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

The following table provides information about the composition of net regulatory assets as of December 31, 2016 and December 31, 2015, and the changes during the year ended December 31, 2016:

Regulatory Assets by Source	December 31, 2016	December 31, 2015	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 90	$ 185	$ (95)
Customer receivables for future income taxes	444	355	89
Nuclear decommissioning and spent fuel disposal costs	(304)	(272)	(32)
Asset removal costs	(470)	(372)	(98)
Deferred transmission costs	127	115	12
Deferred generation costs	215	243	(28)
Deferred distribution costs	296	335	(39)
Contract valuations	153	186	(33)
Storm-related costs	353	403	(50)
Other	110	170	(60)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,014	$ 1,348	$ (334)

Regulatory assets that do not earn a current return totaled approximately $153 million and $148 million as of December 31, 2016 and 2015, respectively, primarily related to storm damage costs, and are currently being recovered through rates.

As of December 31, 2016 and December 31, 2015, FirstEnergy had approximately $157 million and $116 million 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.

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. FES' principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements, and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. Retail customers are metered on a cycle basis.

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

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES. There was no material concentration of receivables as of December 31, 2016 and 2015 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2016 and 2015 are included below.

Customer Receivables	FirstEnergy	FES
	(In millions)	
December 31, 2016		
Billed	$ 833	$ 123
Unbilled	607	90
Total	$ 1,440	$ 213
December 31, 2015		
Billed	$ 836	$ 165
Unbilled	579	110
Total	$ 1,415	$ 275

EARNINGS (LOSS) PER SHARE OF COMMON STOCK

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

Reconciliation of Basic and Diluted Earnings (Loss) per Share of Common Stock	2016	2015	2014
	(In millions, except per share amounts)		
Income (loss) from continuing operations available to common shareholders	$ (6,177)	$ 578	$ 213
Discontinued operations (Note 20)	—	—	86
Net income (loss)	$ (6,177)	$ 578	$ 299
Weighted average number of basic shares outstanding	426	422	420
Assumed exercise of dilutive stock options and awards[1]	—	2	1
Weighted average number of diluted shares outstanding	426	424	421
Earnings (loss) per share:			
Basic earnings (loss) per share:			
Continuing operations	$ (14.49)	$ 1.37	$ 0.51
Discontinued operations (Note 20)	—	—	0.20
Earnings (loss) per basic share	$ (14.49)	$ 1.37	$ 0.71
Diluted earnings (loss) per share:			
Continuing operations	$ (14.49)	$ 1.37	$ 0.51
Discontinued operations (Note 20)	—	—	0.20
Earnings (loss) per diluted share	$ (14.49)	$ 1.37	$ 0.71

(1) For the year ended December 31, 2016, approximately 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 for the period. For the years ended December 31, 2015 and 2014, approximately one million and two million shares were excluded from the calculation of diluted shares outstanding, respectively, as their inclusion would be antidilutive.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. The cost of nuclear fuel is capitalized within the CES segment's Property, plant and equipment and charged to fuel expense using the specific identification method. Property, plant and equipment balances by segment as of December 31, 2016 and 2015 were as follows:

	December 31, 2016				
Property, Plant and Equipment	In Service[1]	Accum. Depr.	Net Plant	CWIP	Total PP&E
			(In millions)		
Regulated Distribution[2]	$ 24,979	$ (7,169)	$ 17,810	$ 472	$ 18,282
Regulated Transmission[2]	9,342	(1,948)	7,394	383	7,777
Competitive Energy Services[3]	8,680	(6,267)	2,413	453	2,866
Corporate/Other	766	(347)	419	43	462
Total	$ 43,767	$ (15,731)	$ 28,036	$ 1,351	$ 29,387

Property, Plant and Equipment	December 31, 2015				
	In Service[(1)]	Accum. Depr.	Net Plant	CWIP	Total PP&E
			(In millions)		
Regulated Distribution[(2)]	$ 24,034	$ (6,865)	$ 17,169	$ 530	$ 17,699
Regulated Transmission[(2)]	8,222	(1,840)	6,382	484	6,866
Competitive Energy Services[(3)]	17,214	(6,213)	11,001	1,304	12,305
Corporate/Other	482	(242)	240	104	344
Total	$ 49,952	$ (15,160)	$ 34,792	$ 2,422	$ 37,214

(1) Includes capital leases of $244 million and $253 million at December 31, 2016 and 2015, respectively.

(2) Net plant in service of $326 million as of December 31, 2015 was reclassified to conform to the current presentation reflecting the transfer of certain transmission assets from Regulated Distribution to Regulated Transmission during the fourth quarter of 2016. See "Note 19, Segment Information", for more information.

(3) Primarily consists of generating assets and nuclear fuel as discussed above.

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

Property, plant and equipment balances for FES as of December 31, 2016 and 2015 were as follows:

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

Property, Plant and Equipment	December 31, 2015				
	In Service	Accum. Depr.	Net Plant	CWIP	Total PP&E
			(In millions)		
Fossil Generation	$ 5,911	$ (1,937)	$ 3,974	$ 218	$ 4,192
Nuclear Generation	5,617	(1,574)	4,043	512	4,555
Nuclear Fuel	2,616	(2,198)	418	283	701
Other	167	(56)	111	144	255
Total	$ 14,311	$ (5,765)	$ 8,546	$ 1,157	$ 9,703

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's and FES' electric plant in 2016, 2015 and 2014 are shown in the following table:

	Annual Composite Depreciation Rate		
	2016	2015	2014
FirstEnergy	2.5%	2.5%	2.5%
FES	3.3%	3.2%	3.1%

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

For the years ended December 31, 2016, 2015 and 2014, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $37 million, $49 million and $49 million, respectively, of allowance for equity funds used during construction and $66 million, $68 million and $69 million, respectively, of capitalized interest.

For the years ended December 31, 2016, 2015 and 2014, capitalized financing costs on FES' Consolidated Statements of Income (Loss) includes $34 million, $35 million and $34 million, respectively, of capitalized interest.

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,003 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, plant and equipment includes $639 million representing AGC's share in this facility as of December 31, 2016 of which $458 million is unregulated and included within the CES segment. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statements of Income (Loss). Approximately 59% of AGC is owned by AE Supply and approximately 41% by MP. As part of FE's strategic review of its competitive operations, on January 18, 2017, AGC entered into an asset purchase agreement with Aspen to sell AE Supply's indirect interest (23.75%) in Bath County, as discussed in "Note 22, Subsequent Events". Additionally, on December 16, 2016, MP issued an RFP for the sale of its ownership interest in Bath County, discussed in "Note 15, Regulatory Matters".

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2016, are described further in "Note 14, Asset Retirement Obligations".

ASSET IMPAIRMENTS

Long-Lived Assets

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

See Note 2, Asset Impairments, for long-lived asset impairments recognized during 2016 and 2015.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair value of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, and CES. The following table presents the changes in the carrying value of goodwill for the year ended December 31, 2016:

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Consolidated
		(In millions)		
Balance as of December 31, 2015	$ 5,092	$ 526	$ 800	$ 6,418
Impairment	—	—	(800)	(800)
Transmission Segment [1]	(88)	88	—	—
Balance as of December 31, 2016	$ 5,004	$ 614	$ —	$ 5,618

[1] See Note 19, Segment Information for discussion of transfer of certain transmission assets from the Regulated Distribution segment to the Regulated Transmission segment during the fourth quarter of 2016, resulting in the transfer of $88 million of goodwill between the segments based on the relative fair value of the transmission assets to fair value of the Regulated Distribution segment.

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

As of July 31, 2016, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units' goodwill, assessing economic, industry and market considerations in addition to the reporting units' overall financial performance. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary.

See Note 2, Asset Impairments, for goodwill impairment recognized during 2016 at CES.

Investments

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

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

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, 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. In 2016, 2015 and 2014, FirstEnergy recognized $21 million, $102 million and $37 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $19 million, $90 million and $33 million, respectively. The fair values of FirstEnergy’s investments are disclosed in Note 10, Fair Value Measurements.

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

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

INVENTORY

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

See Note 2, Asset Impairments, for inventory-related charges recognized during 2016.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers". Subsequent accounting standards updates have been issued which amend and/or clarify the application of ASU 2014-09. The core principle of the new guidance is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. More detailed disclosures will also be required to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, the new revenue recognition guidance will be effective for annual and interim reporting periods beginning after December 15, 2017. Earlier adoption is permitted for annual and interim reporting periods beginning after December 15, 2016. FirstEnergy will not early adopt the standards. The standards shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy has evaluated a significant portion of its revenues and preliminarily expects limited impacts to current revenue recognition practices, dependent on the resolution of industry issues including accounting for contributions in aid of construction and the ability to recognize revenue for contracts where collectibility is in question. FirstEnergy continues to assess the remainder of its revenue streams and the impact on its financial statements and disclosures as well as which transition method it will select to adopt the guidance.

On August 27, 2014, the FASB issued ASU 2014-15, "Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." In connection with preparing financial statements for each annual and interim reporting period, the ASU requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Disclosures are required when management identifies conditions or events that raise substantial doubt. The new requirements were effective for the annual period ended December 31, 2016.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities", which primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption for certain provisions can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)", which will require organizations that lease assets with lease terms of more than twelve 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. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In March of 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting", which simplifies several aspects of the accounting for employee share-based payment. The new guidance will require all income tax effects of awards to be recognized in the income statement when the awards vest or are settled. It also will not require liability accounting when an employer repurchases more of an employee's shares for tax withholding purposes. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. Upon adoption, January 1, 2017, FirstEnergy elected to account for forfeitures as they occur. The adoption of the ASU did not have a material impact on FirstEnergy's financial statements.

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments", which removes all recognition thresholds and will require companies to recognize an allowance for credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost that the company expects to collect over the instrument's contractual life. The ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted for fiscal years beginning after December 15, 2018. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments". 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. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted for all entities. FirstEnergy expects to adopt this ASU in 2017 and does not expect this ASU to have a material effect on its financial statements.

In October 2016, the FASB issued ASU 2016-16, " Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory". ASU 2016-16 eliminates the exception for all intra-entity sales of assets other than inventory, which allows companies to defer the tax effects of intra-entity asset transfers. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller's tax jurisdiction when the intra-entity transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. Any deferred tax asset that arises in the buyer's jurisdiction would also be recognized at the time of the transfer. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted and the modified retrospective approach will be required for transition to the new guidance, with a cumulative-effect adjustment recorded in retained earnings as of the beginning of the period of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash" that will require entities to show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. As a result, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statement of cash flows. When cash, cash equivalents, restricted cash and restricted cash equivalents are presented in more than one line item on the balance sheet, the new guidance requires a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2019. Early adoption in an interim period is permitted, but any adjustments must be reflected as of the beginning of the fiscal year that includes that interim period. FirstEnergy does not expect this ASU to have a material effect on its financial statements.

Additionally, during 2016, the FASB issued the following ASUs:

- ASU 2016-05, "Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships,"
- ASU 2016-06, "Contingent Put and Call Options in Debt Instruments (a consensus of the FASB Emerging Issues Task Force),"
- ASU 2016-07, "Simplifying the Transition to the Equity Method of Accounting," and
- ASU 2016-17, "Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control."

FirstEnergy does not expect these ASUs to have a material effect on its financial statements.

2. ASSET IMPAIRMENTS

Property, Plant, and Equipment

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

As disclosed in Note 1, Organization and Basis of Presentation, in November 2016, FirstEnergy announced that it had begun a strategic review of its competitive operations as it transitions to a fully regulated utility with a target to implement its exit from competitive operations by mid-2018.

Although FirstEnergy is targeting mid-2018 to exit from competitive operations, the options for the remaining portion of CES' generation 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,
- Additional asset sales and/or plant deactivations,
- Restructuring FES debt with its creditors, and/or
- Seeking protection under U.S. bankruptcy laws for FES and possibly FENOC.

Once a plan is finalized, FE’s implementation of that plan may result in long-lived asset impairment charges, exit related losses and costs, contingencies, and reserves against deferred tax assets that may not be realizable.

As part of assessing the viability of strategic alternatives, FirstEnergy determined that the carrying value of long-lived assets of the competitive business were not recoverable, specifically given FirstEnergy’s target to implement its exit from competitive operations by mid-2018, significantly before the end of the original useful lives, and the anticipated cash flows over this shortened period. As a result, CES recorded a non-cash pre-tax impairment charge of $9,218 million ($8,082 million at FES) in the fourth quarter of 2016 to reduce the carrying value of certain assets to their estimated fair value, including long-lived assets, such as generating plants and nuclear fuel, as well as other assets, such as materials and supplies.

	FE Consolidated			**FES Consolidated**		
Impaired Asset	**Net Book Value**	**Fair Value**	**Impairment**	**Net Book Value**	**Fair Value**	**Impairment**
			(In millions)			
Coal generation assets	$ 4,672	$ 614	$ 4,058	$ 3,699	$ 435	$ 3,264
Nuclear generation assets	4,842	460	4,382	4,825	460	4,365
Gas/Hydro generation assets	1,187	921	266	—	—	—
Nuclear Fuel	703	460	243	703	460	243
Other assets (1)	382	113	269	314	104	210
Totals	$ 11,786	$ 2,568	$ 9,218	$ 9,541	$ 1,459	$ 8,082

(1) Includes the impairment of materials and supplies ($142 million), AE Supply coal contracts ($55 million) and AE Supply's investment in OVEC ($37 million).

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

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

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).

3. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the years ended December 31, 2016, 2015 and 2014 for FirstEnergy are shown in the following table:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2014	$ (36)	$ 9	$ 311	$ 284
Other comprehensive income before reclassifications	—	89	92	181
Amounts reclassified from AOCI	(2)	(63)	(168)	(233)
Other comprehensive income (loss)	(2)	26	(76)	(52)
Income tax (benefits) on other comprehensive income (loss)	(1)	10	(23)	(14)
Other comprehensive income (loss), net of tax	(1)	16	(53)	(38)
AOCI Balance, December 31, 2014	$ (37)	$ 25	$ 258	$ 246
Other comprehensive income before reclassifications	—	14	10	24
Amounts reclassified from AOCI	5	(25)	(126)	(146)
Other comprehensive income (loss)	5	(11)	(116)	(122)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(44)	(47)
Other comprehensive income (loss), net of tax	4	(7)	(72)	(75)
AOCI Balance, December 31, 2015	$ (33)	$ 18	$ 186	$ 171
Other comprehensive income before reclassifications	—	106	13	119
Amounts reclassified from AOCI	8	(51)	(72)	(115)
Other comprehensive income (loss)	8	55	(59)	4
Income tax (benefits) on other comprehensive income (loss)	3	21	(23)	1
Other comprehensive income (loss), net of tax	5	34	(36)	3
AOCI Balance, December 31, 2016	$ (28)	$ 52	$ 150	$ 174

The following amounts were reclassified from AOCI for FirstEnergy in the years ended December 31, 2016, 2015 and 2014:

FirstEnergy **Reclassifications from AOCI** [2]	**Year Ended December 31**			**Affected Line Item in Consolidated Statements of Income (Loss)**
	2016	**2015**	**2014**	
		(In millions)		
Gains & losses on cash flow hedges				
Commodity contracts	$ —	$ (3)	$ (10)	Other operating expenses
Long-term debt	8	8	8	Interest expense
	8	5	(2)	Total before taxes
	(3)	(1)	1	Income taxes (benefits)
	$ 5	$ 4	$ (1)	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (51)	$ (25)	$ (63)	Investment income (loss)
	19	9	24	Income taxes (benefits)
	$ (32)	$ (16)	$ (39)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (72)	$ (126)	$ (168)	[1]
	27	49	65	Income taxes (benefits)
	$ (45)	$ (77)	$ (103)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

The changes in AOCI for the years ended December 31, 2016, 2015 and 2014 for FES are shown in the following table:

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance, January 1, 2014	$ (1)	$ 8	$ 47	$ 54
Other comprehensive income before reclassifications	—	80	13	93
Amounts reclassified from AOCI	(10)	(59)	(19)	(88)
Other comprehensive income (loss)	(10)	21	(6)	5
Income tax (benefits) on other comprehensive income (loss)	(4)	8	(2)	2
Other comprehensive income (loss), net of tax	(6)	13	(4)	3
AOCI Balance, December 31, 2014	$ (7)	$ 21	$ 43	$ 57
Other comprehensive income before reclassifications	—	15	10	25
Amounts reclassified from AOCI	(3)	(24)	(16)	(43)
Other comprehensive loss	(3)	(9)	(6)	(18)
Income tax benefits on other comprehensive loss	(1)	(4)	(2)	(7)
Other comprehensive loss, net of tax	(2)	(5)	(4)	(11)
AOCI Balance, December 31, 2015	$ (9)	$ 16	$ 39	$ 46
Other comprehensive income before reclassifications	—	100	—	100
Amounts reclassified from AOCI	—	(48)	(14)	(62)
Other comprehensive income (loss)	—	52	(14)	38
Income tax (benefits) on other comprehensive income (loss)	—	20	(5)	15
Other comprehensive income (loss), net of tax	—	32	(9)	23
AOCI Balance, December 31, 2016	$ (9)	$ 48	$ 30	$ 69

The following amounts were reclassified from AOCI for FES in the years ended December 31, 2016, 2015 and 2014:

FES

Reclassifications from AOCI (2)	Year Ended December 31			Affected Line Item in Consolidated Statements of Income (Loss)
	2016	2015	2014	
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ —	$ (3)	$ (10)	Other operating expenses
	—	1	4	Income taxes (benefits)
	$ —	$ (2)	$ (6)	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (48)	$ (24)	$ (59)	Investment income (loss)
	18	9	22	Income taxes (benefits)
	$ (30)	$ (15)	$ (37)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (14)	$ (16)	$ (19)	(1)
	5	6	7	Income taxes (benefits)
	$ (9)	$ (10)	$ (12)	Net of tax

(1) These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pension and Other Postemployment Benefits for additional details.

(2) Parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

4. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pension and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. In 2014, the qualified pension plan was amended authorizing a voluntary cashout window program for certain eligible terminated participants with vested benefits. Payment of benefits for participants that elected an immediate lump sum cash payment or an annuity resulted in a $40 million reduction to the underfunded status of the pension plan. Additionally, during 2016 and 2015, certain unions ratified their labor agreements that ended subsidized retiree health care resulting in a reduction to the OPEB benefit obligation by approximately $13 million and $10 million, respectively.

FirstEnergy recognizes a pension and OPEB mark-to-market adjustment for the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2016, 2015, and 2014 were $194 million ($147 million net of amounts capitalized), $369 million ($242 million net of amounts capitalized), and $1,243 million ($835 million net of amounts capitalized), respectively. In 2016, the pension and OPEB mark-to-market adjustment primarily reflects a 25 basis point decline in the discount rate, partially offset by changes in actuarial assumptions, including mortality assumptions and higher than expected asset returns.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. In 2016, FirstEnergy satisfied its minimum required funding obligations of $382 million and addressed funding obligations for future years to its qualified pension plan with total contributions of $882 million (of which $138 million was cash contributions from FES), including $500 million of FE common stock contributed to the qualified pension plan on December 13, 2016.

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

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2016, FirstEnergy's qualified pension and OPEB plan assets experienced gains of $472 million, or 8.2% compared to losses of $(172) million, or (2.7)% in 2015 and earnings of $387 million, or 6.2% in 2014, and assumed a 7.50% rate of return for 2016 and a 7.75% rate of return for 2015 and 2014 on plan assets which generated $429 million, $476 million and $496 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

During 2016, the Society of Actuaries released its updated mortality improvement scale for pension plans, MP-2016, incorporating three additional years of SSA data on U.S. population mortality. MP-2016 incorporates SSA mortality data from 2012 to 2014 and a slight modification of two input values designed to improve the model's year-over-year stability. The updated improvement scale indicates a slight decline in life expectancy as a result of the slower average rate of mortality improvement. Due to the additional years of data on population mortality, the RP2014 mortality table with the projection scale MP-2016 was utilized to determine the 2016 benefit cost and obligation as of December 31, 2016 for the FirstEnergy pension and OPEB plans. The impact of using the projection scale MP-2016 resulted in a decrease in the projected benefit obligation of $141 million and $8 million for the pension and OPEB plans, respectively, and was included in the 2016 pension and OPEB mark-to-market adjustment.

Obligations and Funded Status - Qualified and Non-Qualified Plans	Pension 2016	Pension 2015	OPEB 2016	OPEB 2015
	(In millions)			
Change in benefit obligation:				
Benefit obligation as of January 1	$ 9,079	$ 9,249	$ 724	$ 757
Service cost	191	193	5	5
Interest cost	398	383	30	29
Plan participants' contributions	—	—	5	6
Plan amendments	—	—	(13)	(10)
Medicare retiree drug subsidy	—	—	1	1
Actuarial (gain) loss	224	(277)	14	(2)
Benefits paid	(466)	(469)	(55)	(62)
Benefit obligation as of December 31	$ 9,426	$ 9,079	$ 711	$ 724
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$ 5,338	$ 5,824	$ 431	$ 464
Actual return (losses) on plan assets	442	(178)	30	6
Company contributions	899	161	9	17
Plan participants' contributions	—	—	5	6
Benefits paid	(466)	(469)	(55)	(62)
Fair value of plan assets as of December 31	$ 6,213	$ 5,338	$ 420	$ 431
Funded Status:				
Qualified plan	$ (2,821)	$ (3,366)		
Non-qualified plans	(392)	(375)		
Funded Status	$ (3,213)	$ (3,741)	$ (291)	$ (293)
Accumulated benefit obligation	$ 8,913	$ 8,579	$ —	$ —
Amounts Recognized on the Balance Sheet:				
Noncurrent assets	$ 9	$ —	$ —	$ —
Current liabilities	(19)	(18)	—	—
Noncurrent liabilities	(3,203)	(3,723)	(291)	(293)
Net liability as of December 31	$ (3,213)	$ (3,741)	$ (291)	$ (293)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$ 28	$ 37	$ (288)	$ (355)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	4.25%	4.50%	4.00%	4.25%
Rate of compensation increase	4.20%	4.20%	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	6.0-5.5%	6.0-5.5%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.5%	4.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2027	2026
Allocation of Plan Assets (as of December 31)				
Equity securities	44%	40%	53%	51%
Bonds	30%	34%	41%	43%
Absolute return strategies	8%	7%	—%	—%
Real estate	10%	11%	—%	—%
Cash and short-term securities	8%	8%	6%	6%
Total	100%	100%	100%	100%

The estimated 2017 amortization of pension and OPEB prior service costs (credits) from AOCI into net periodic pension and OPEB costs (credits) is approximately $8 million and $(81) million, respectively.

Components of Net Periodic Benefit Costs	Pension 2016	Pension 2015	Pension 2014	OPEB 2016	OPEB 2015	OPEB 2014
	(In millions)					
Service cost	$ 191	$ 193	$ 167	$ 5	$ 5	$ 9
Interest cost	398	383	402	30	29	39
Expected return on plan assets	(399)	(443)	(462)	(30)	(33)	(34)
Amortization of prior service cost (credit)	8	8	8	(80)	(134)	(176)
Pension & OPEB mark-to-market adjustment	179	344	1,235	15	25	8
Net periodic benefit cost (credit)	$ 377	$ 485	$ 1,350	$ (60)	$ (108)	$ (154)

Assumptions Used to Determine Net Periodic Benefit Cost * for Years Ended December 31	Pension 2016	Pension 2015	Pension 2014	OPEB 2016	OPEB 2015	OPEB 2014
Weighted-average discount rate	4.50%	4.25%	5.00%	4.25%	4.00%	4.75%
Expected long-term return on plan assets	7.50%	7.75%	7.75%	7.50%	7.75%	7.75%
Rate of compensation increase	4.20%	4.20%	4.20%	N/A	N/A	N/A

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

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

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 10, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2016 and 2015.

	December 31, 2016				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 464	$ —	$ 464	8%
Equity investments					
Domestic [(2)]	1,048	13	—	1,061	17%
International	422	1,269	—	1,691	27%
Fixed income					
Government bonds	—	106	—	106	2%
Corporate bonds	—	1,245	—	1,245	20%
High yield debt	—	372	—	372	6%
Mortgage-backed securities (non-government)	—	112	—	112	2%
Alternatives					
Hedge funds (Absolute return)	—	500	—	500	8%
Derivatives	—	(1)	—	(1)	—%
Private equity funds	—	—	33	33	—%
Real estate funds	—	—	615	615	10%
Total [(1)]	$ 1,470	$ 4,080	$ 648	$ 6,198	100%

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

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

	December 31, 2015				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 427	$ —	$ 427	8%
Equity investments					
Domestic	869	75	—	944	18%
International	395	794	—	1,189	22%
Fixed income					
Government bonds	—	232	—	232	4%
Corporate bonds	—	1,115	—	1,115	21%
High yield debt	—	438	—	438	8%
Mortgage-backed securities (non-government)	—	31	—	31	1%
Alternatives					
Hedge funds (Absolute return)	—	343	—	343	7%
Derivatives	—	15	—	15	—%
Private equity funds	—	—	24	24	—%
Real estate funds	—	—	587	587	11%
Total [(1)]	$ 1,264	$ 3,470	$ 611	$ 5,345	100%

(1) Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2016 and 2015:

	Private Equity Funds	Real Estate Funds
	(In millions)	
Balance as of January 1, 2015	$ 25	$ 421
Actual return on plan assets:		
Unrealized gains	—	42
Realized gains (losses)	(1)	16
Transfers in	—	108
Balance as of December 31, 2015	$ 24	$ 587
Actual return on plan assets:		
Unrealized gains	1	29
Realized gains	1	14
Transfers in (out)	7	(15)
Balance as of December 31, 2016	$ 33	$ 615

As of December 31, 2016 and 2015, the OPEB trust investments measured at fair value were as follows:

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

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

	December 31, 2015				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 25	$ —	$ 25	6%
Equity investment					
Domestic	219	—	—	219	50%
International	1	3	—	4	1%
Fixed income					
U.S. treasuries	—	42	—	42	10%
Government bonds	—	114	—	114	26%
Corporate bonds	—	27	—	27	6%
High yield debt	—	1	—	1	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	1	—	1	—%
Real estate funds	—	—	2	2	—%
Total [1]	$ 220	$ 216	$ 2	$ 438	100%

[1] Excludes $(7) million as of December 31, 2015, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2016 and 2015:

	Real Estate Funds
	(in millions)
Balance as of January 1, 2015	$ 3
Transfers out	(1)
Balance as of December 31, 2015	$ 2
Transfers out	(2)
Balance as of December 31, 2016	$ —

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

FirstEnergy's target asset allocations for its pension and OPEB trust portfolios for 2016 and 2015 are shown in the following table:

Target Asset Allocations	
Equities	38%
Fixed income	30%
Absolute return strategies	8%
Real estate	10%
Alternative investments	8%
Cash	6%
	100%

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 1	$ (1)
Effect on accumulated benefit obligation	$ 23	$ (20)

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

	Pension	OPEB Benefit Payments	OPEB Subsidy Receipts
		(In millions)	
2016	$ 505	$ 52	$ (3)
2017	523	52	(3)
2018	534	53	(3)
2019	552	53	(3)
2020	566	53	(3)
Years 2021-2025	2,999	251	(7)

FES' share of the pension and OPEB net (liability) asset as of December 31, 2016 and 2015, was as follows:

	Pension		OPEB	
	2016	2015	2016	2015
		(In millions)		
Net (Liability) Asset(1)	$ (158)	$ (303)	$ 36	$ 25

(1) Excludes $866 million and $785 million as of December 31, 2016 and 2015, respectively, of affiliated non-current liabilities related to pension and OPEB mark-to-market costs allocated to FES of which $570 million and $518 million, respectively, are from FENOC.

FES' share of the net periodic benefit cost (credit), including the pension and OPEB mark-to-market adjustment, for the three years ended December 31, 2016 was as follows:

	Pension			OPEB		
	2016	2015	2014	2016	2015	2014
			(In millions)			
Net Periodic Cost (Credit)	$ (5)	$ 10	$ 150	$ (26)	$ (22)	$ (24)

5. STOCK-BASED COMPENSATION PLANS

FirstEnergy grants stock-based awards through the ICP 2015, primarily in the form of restricted stock and performance-based restricted stock units. Under FirstEnergy's previous incentive compensation plan, the ICP 2007, FirstEnergy also granted stock options and performance shares. The ICP 2007 and ICP 2015 include shareholder authorization to issue 29 million shares and 10 million shares, respectively, of common stock or their equivalent. As of December 31, 2016, approximately 8.0 million shares were available for future grants under the ICP 2015 assuming maximum performance metrics are achieved for the outstanding cycles of restricted stock units. No shares are available for future grants under the ICP 2007. Any shares not issued due to forfeitures or cancellations are added back to the ICP 2015. Shares used under the ICP 2007 and ICP 2015 are issued from authorized but unissued common stock. Vesting periods range from one to ten years, with the majority of awards having a vesting period of three years. FirstEnergy also issues stock through its 401(k) Savings Plan, EDCP, and DCPD. Currently, FirstEnergy records the compensation costs for stock-based compensation awards that will be paid in stock over the vesting period based on the fair value on the grant date, less estimated forfeitures. Beginning in 2017, based upon the adoption of ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting", FE has elected to account for forfeitures as they occur. FirstEnergy adjusts the compensation costs for stock-based compensation awards that will be paid in cash based on changes in the fair value of the award as of each reporting date. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or settled. Actual income tax benefits realized during the years ended December 31, 2016, 2015 and 2014 were $13 million, $10 million and $13 million, respectively. Currently, the excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as a financing activity on the Consolidated Statements of Cash Flows. Beginning in 2017, based upon the adoption of ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting", the income tax effects of awards will be recognized in the income statement when the awards vest or are settled.

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

FirstEnergy **Stock-based Compensation Plan**	**Years ended December 31** **2016**	 **2015**	 **2014**
		(In millions)	
Restricted Stock Units	$ 62	$ 46	$ 26
Restricted Stock	2	2	5
Performance Shares	(3)	—	5
401(k) Savings Plan	39	38	25
EDCP & DCPD	5	3	8
Total	$ 105	$ 89	$ 69
Stock-based compensation costs capitalized	$ 38	$ 32	$ 23

FES **Stock-based Compensation Plan**	**Years ended December 31** **2016**	 **2015**	 **2014**
		(In millions)	
Restricted Stock Units	$ 11	$ 6	$ 4
Performance Shares	—	—	1
401(k) Savings Plan	5	5	4
Total	$ 16	$ 11	$ 9
Stock-based compensation costs capitalized	$ 2	$ 1	$ 1

Stock option expense was not material for FirstEnergy or FES for the years December 31, 2016, 2015 or 2014. Income tax benefits associated with stock based compensation plan expense were $14 million, $12 million and $14 million (FES - $2 million, $2 million and $2 million) for the years ended 2016, 2015 and 2014, respectively.

Restricted Stock Units

Beginning with the performance-based restricted stock units granted in 2015, two-thirds will be paid in stock and one-third will be paid in cash. Prior to 2015, all performance-based restricted stock units were paid in stock. Restricted stock units paid in stock provide the participant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets. The grant date fair value of the stock portion of the restricted stock unit award is measured based on the average of the high and low prices of FE common stock on the date of grant. Restricted stock units paid in cash provide the participant the right to receive cash based on the numbers of stock units set forth in the agreement and value of the equivalent number of shares of FE common stock as of the vesting date. The cash portion of the restricted stock unit award is considered a liability award, which is remeasured each period based on FE's stock price and projected performance adjustments. The liability recorded for cash performance based restricted stock units as of December 31, 2016 was $14 million. No cash was paid to settle the restricted stock unit obligations in 2016. The vesting period for each of the awards was three years. Dividend equivalents are received on the restricted stock units and are reinvested in additional restricted stock units and subject to the same performance conditions.

Restricted stock unit activity for the year ended December 31, 2016, was as follows:

Restricted Stock Unit Activity	Shares	Weighted-Average Grant Date Fair Value
Nonvested as of January 1, 2016	2,436,888	$ 35.26
Granted in 2016	1,581,762	34.77
Forfeited in 2016	(81,618)	33.85
Vested in 2016[1]	(873,303)	33.54
Nonvested as of December 31, 2016	3,063,729	$ 32.98

[1] Excludes dividend equivalents of 132,360 earned during vesting period

The weighted average fair value of awards granted in 2016, 2015 and 2014 were $34.77, $35.27 and $32.17 respectively. For the years ended December 31, 2016, 2015, and 2014, the fair value of restricted stock units vested was $36 million, $22 million, and $28 million, respectively. As of December 31, 2016, there was $47 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock units; that cost is expected to be recognized over a period of approximately two years.

Restricted Stock

Certain employees receive awards of FE restricted stock (as opposed to "units" with the right to receive shares at the end of the restriction period) subject to restrictions that lapse over a defined period of time or upon achieving performance results. The fair value of restricted stock is measured based on the average of the high and low prices of FirstEnergy common stock on the date of grant. Dividends are received on the restricted stock and are reinvested in additional shares of restricted stock.

Restricted common stock (restricted stock) activity for the year ended December 31, 2016, was as follows:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2016	190,656	$ 40.65
Granted in 2016	28,756	32.69
Vested in 2016[1]	(82,252)	46.83
Nonvested as of December 31, 2016	137,160	$ 35.27

[1] Excludes 23,402 shares for dividends earned during vesting period

The weighted average vesting period for restricted stock granted in 2016 was 3.49 years. The weighted average fair value of awards granted in 2016, 2015, and 2014 were $32.69, $32.98 and $32.71 respectively. For the years ended December 31, 2016, 2015, and 2014, the fair value of restricted stock vested was $5 million, $8 million, and $4 million, respectively. As of December 31, 2016, there was $2 million of total unrecognized compensation cost related to non-vested restricted stock, which is expected to be recognized over a period of approximately three years.

Stock Options

Stock options have been granted to certain employees allowing them to purchase a specified number of common shares at a fixed exercise price over a defined period of time. Stock options generally expire ten years from the date of grant. There were no stock options granted in 2016. Stock option activity during 2016 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2016 (1,211,358 options exercisable)	1,411,971	$ 44.89
Options forfeited	(35,150)	56.40
Balance, December 31, 2016 (1,376,821 options exercisable)	1,376,821	$ 44.60

There was no cash received from the exercise of stock options in 2016. Cash received from the exercise of stock options in 2015 and 2014 was not material. The weighted-average remaining contractual term of options outstanding as of December 31, 2016 was 3.60 years.

Performance Shares

Prior to the 2015 grant of performance-based restricted stock units discussed above, the Company granted performance shares. Performance shares are share equivalents and do not have voting rights. The performance shares outstanding track the performance of FE's common stock over a three-year vesting period. Dividend equivalents accrue on performance shares and are reinvested into additional performance shares with the same performance conditions. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. In 2016, $2 million cash was paid to settle performance shares that vested over the 2013-2015 performance cycle. During 2015, no cash was paid to settle performance shares because the performance criteria was not met for the 2012-2014 cycle.

401(k) Savings Plan

In 2016 and 2015, 1,159,215 and 1,072,494 shares of FE common stock, respectively, were issued and contributed to participants' accounts.

EDCP

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

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their equity retainers to deferred stock and their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $7 million and $9 million as of December 31, 2016 and December 31, 2015, respectively, is included in the caption “Retirement benefits” on the Consolidated Balance Sheets.

6. TAXES

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

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

INCOME TAXES (BENEFITS)[1]	2016	2015	2014
		(In millions)	
FirstEnergy			
Currently payable (receivable)-			
Federal	$ (1)	$ 1	$ (132)
State	9	30	(72)
	8	31	(204)
Deferred, net-			
Federal	(3,114)	277	214
State	59	15	(42)
	(3,055)	292	172
Investment tax credit amortization	(8)	(8)	(10)
Total provision for income taxes (benefits)	$ (3,055)	$ 315	$ (42)
FES			
Currently payable (receivable)-			
Federal	$ (67)	$ (56)	$ (222)
State	(1)	2	(13)
	(68)	(54)	(235)
Deferred, net-			
Federal	(2,861)	103	25
State	(57)	18	(14)
	(2,918)	121	11
Investment tax credit amortization	(2)	(2)	(4)
Total provision for income taxes (benefits)	$ (2,988)	$ 65	$ (228)

(1) Provision for Income Taxes (Benefits) on Income from Continuing Operations. Currently payable (receivable) in 2014 excludes $106 million and $12 million of federal and state taxes, respectively, associated with discontinued operations. Deferred, net in 2014 excludes $44 million and $5 million of federal and state tax benefits, respectively, associated with discontinued operations.

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

	2016	2015	2014
		(In millions)	
FirstEnergy			
Income (loss) from Continuing Operations before income taxes (benefits)	$ (9,232)	$ 893	$ 171
Federal income tax expense (benefit) at statutory rate (35%)	$ (3,231)	$ 313	$ 60
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	(192)	17	(21)
AFUDC equity and other flow-through	(13)	(16)	(13)
Amortization of investment tax credits	(8)	(8)	(10)
Change in accounting method	—	(8)	(27)
ESOP dividend	(6)	(6)	(6)
Impairment of non-deductible goodwill	157	—	—
Tax basis balance sheet adjustments	—	—	(25)
Uncertain tax positions	(16)	1	(35)
Valuation allowances	246	18	33
Other, net	8	4	2
Total income taxes (benefits)	$ (3,055)	$ 315	$ (42)
Effective income tax rate	33.1%	35.3%	(24.6)%
FES			
Income (loss) from Continuing Operations before income taxes (benefits)	$ (8,444)	$ 147	$ (588)
Federal income tax expense (benefit) at statutory rate (35%)	$ (2,955)	$ 51	$ (206)
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	(188)	2	(28)
Amortization of investment tax credits	(2)	(2)	(4)
ESOP dividend	(1)	(1)	(1)
Impairment of non-deductible goodwill	9	—	—
Uncertain tax positions	(8)	5	—
Valuation allowances	151	14	14
Other, net	6	(4)	(3)
Total income taxes (benefits)	$ (2,988)	$ 65	$ (228)
Effective income tax rate	35.4%	44.2%	38.8 %

In 2016, FirstEnergy's effective tax rate was 33.1% compared to 35.3% in 2015. The change in the effective tax rate year-over-year resulted from the impairment of $800 million of goodwill (as described in Note 2, Asset Impairments), of which $433 million is non-deductible for tax purposes. Additionally, $168 million of valuation allowances were recorded against state and local NOL carryforwards and $78 million of valuation allowances were recorded against state and local property deferred tax assets, that management believes, more likely than not, will not be realized.

In 2016, FES' effective tax rate on income from continuing operations was 35.4% compared to 44.2% in 2015. The change in the effective tax rate primarily resulted from $73 million of valuation allowances recorded against state and local NOL carryforwards and $78 million of valuation allowances recorded against state and local property deferred tax assets, that management believes, more likely than not, will not be realized, as well as the impairment of $23 million of goodwill, which is non-deductible for tax purposes.

Accumulated deferred income taxes as of December 31, 2016 and 2015 are as follows:

	2016	2015
	(In millions)	
FirstEnergy		
Property basis differences	$ 7,088	$ 9,920
Deferred sale and leaseback gain	(351)	(360)
Pension and OPEB	(1,347)	(1,541)
Nuclear decommissioning activities	635	480
Asset retirement obligations	(669)	(731)
Regulatory asset/liability	545	763
Deferred compensation	(269)	(239)
Loss carryforwards and AMT credits	(2,251)	(1,965)
Valuation reserve	438	192
All other	(54)	254
Net deferred income tax liability	$ 3,765	$ 6,773
FES		
Property basis differences	$ (1,009)	$ 1,901
Deferred sale and leaseback gain	(328)	(342)
Pension and OPEB	(366)	(393)
Lease market valuation liability	111	95
Nuclear decommissioning activities	540	483
Asset retirement obligations	(453)	(509)
Loss carryforwards and AMT credits	(830)	(687)
Valuation reserve	197	46
All other	(141)	6
Net deferred income tax liability (asset)	$ (2,279)	$ 600

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state taxing authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2012-2015. In February 2016, the IRS completed its examination of the 2014 federal income tax return and issued a Full Acceptance Letter with no changes or adjustments to FirstEnergy’s taxable income or effective tax rate. Tax year 2015 is currently under review by the IRS.

FirstEnergy has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2016, the deferred income tax assets, before any valuation allowances, for loss carryforwards and AMT credits consisted of $1.8 billion of Federal NOL carryforwards that will begin to expire in 2030, Federal AMT credits of $25 million that have an indefinite carryforward period, and $407 million of state and local NOL carryforwards that will begin to expire in 2017.

FES has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2016, the deferred income tax assets, before any valuation allowances, for loss carryforwards consisted of $706 million of Federal NOL carryforwards that will begin to expire in 2031 and $120 million of state and local NOL carryforwards that will begin to expire in 2017.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $10.1 billion ($407 million after-tax) for FirstEnergy, of which approximately $2.1 billion ($87 million after-tax) is expected to be utilized based on current estimates and assumptions. FES’ pre-tax NOL carryforwards for state and local income tax purposes is approximately $3.4 billion ($120 million after-tax), of which none is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

Expiration Period	FirstEnergy		FES	
	(In millions)			
	State	Local	State	Local
2017-2021	$ 166	$ 2,998	$ 2	$ 1,795
2022-2026	1,327	—	—	—
2027-2031	2,817	—	410	—
2032-2036	2,752	—	1,172	—
	$ 7,062	$ 2,998	$ 1,584	$ 1,795

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. A recognition threshold and measurement attribute is utilized for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2016 and 2015, FirstEnergy's total unrecognized income tax benefits were approximately $84 million and $34 million, respectively. If ultimately recognized in future years, approximately $50 million of unrecognized income tax benefits would impact the effective tax rate. As of December 31, 2016, it is reasonably possible that approximately $51 million of unrecognized tax benefits may be resolved during 2017 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.

The following table summarizes the changes in unrecognized tax positions for the years ended 2016, 2015 and 2014:

	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2014	$ 48	$ 3
Current year increases	4	—
Prior years increases	5	—
Prior years decreases	(23)	—
Balance, December 31, 2014	$ 34	$ 3
Current year increases	3	—
Prior years increases	7	5
Prior years decreases	(10)	—
Balance, December 31, 2015	$ 34	$ 8
Current year increases	2	—
Prior years increases	69	—
Prior years decreases	(21)	(8)
Balance, December 31, 2016	$ 84	$ —

FirstEnergy recognizes interest expense or income and penalties related to uncertain tax positions in income taxes. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy's recognition of net interest associated with unrecognized tax benefits in 2016, 2015, and 2014 was not material. For the years ended December 31, 2016 and 2015, the cumulative net interest payable recorded by FirstEnergy was not material.

General Taxes

General tax expense for 2016, 2015 and 2014, is summarized as follows:

	2016	2015	2014
		(In millions)	
FirstEnergy			
KWH excise	$ 196	$ 193	$ 194
State gross receipts	212	224	226
Real and personal property	472	410	393
Social security and unemployment	127	119	112
Other	35	32	37
Total general taxes	$ 1,042	$ 978	$ 962
FES			
State gross receipts	$ 28	$ 44	$ 69
Real and personal property	42	36	39
Social security and unemployment	15	16	17
Other	3	2	3
Total general taxes	$ 88	$ 98	$ 128

7. LEASES

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

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years, which expired in 2016 for Perry Unit 1 and will expire in 2017 for Beaver Valley Unit 2. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and entered into similar operating leases for lease terms of approximately 30 years expiring in 2017. OE, CEI and TE had the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

In 2007, FG completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years, expiring in 2040. FES has unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Upon the completion of this transaction, NG will have obtained all of the lessor equity interests at Beaver Valley Unit 2. Therefore, upon the expiration of the Beaver Valley Unit 2 leases, NG will be the sole owner of Beaver Valley Unit 2 and entitled to 100% of the unit's output.

In November 2014, NG repurchased 55.3 MWs of lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. On May 23, 2016, NG completed the purchase of the 3.75% lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 for $50 million. In addition, the Perry Unit 1 leases expired in accordance with their terms on May 30, 2016, resulting in NG being the sole owner of Perry Unit 1 and entitled to100% of the unit's output.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. The PNBV arrangements effectively reduce lease costs related to those transactions (see "Note 9, Variable Interest Entities").

As of December 31, 2016, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2 and FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

Operating lease expense for 2016, 2015 and 2014, is summarized as follows:

(In millions)	**2016**	**2015**	**2014**
FirstEnergy	$ 168	$ 174	$ 199
FES	$ 94	$ 94	$ 95

The future minimum capital lease payments as of December 31, 2016 are as follows:

Capital leases	FirstEnergy	FES
	(In millions)	
2017	$ 32	$ 6
2018	25	2
2019	19	—
2020	14	—
2021	12	—
Years thereafter	15	1
Total minimum lease payments	117	9
Interest portion	(13)	(1)
Present value of net minimum lease payments	104	8
Less current portion	29	5
Noncurrent portion	$ 75	$ 3

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2016, are as follows:

Operating Leases	FirstEnergy
	(In millions)
2017[1]	$ 125
2018	142
2019	123
2020	97
2021	119
Years thereafter	1,351
Total minimum lease payments	$ 1,957

[1] Includes a $3 million payment PNBV Trust will receive associated with certain sale and leaseback transactions. These arrangements, which expire in 2017, effectively reduce lease costs related to those transactions.

FES' future minimum operating lease payments as of December 31, 2016, are as follows:

Operating Leases	FES
	(In millions)
2017	$ 82
2018	101
2019	97
2020	68
2021	93
Years thereafter	1,222
Total minimum lease payments	$ 1,663

8. INTANGIBLE ASSETS

As of December 31, 2016, intangible assets classified in Customer Intangibles and Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, include the following:

	Intangible Assets			Amortization Expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2016	2017	2018	2019	2020	2021	Thereafter
NUG contracts[(1)]	$ 124	$ 31	$ 93	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 68
OVEC[(2)]	54	48	6	2	1	1	—	—	—	4
Coal contracts[(2)(3)(4)]	556	544	12	55	—	—	—	—	—	—
FES customer contracts[(5)]	148	139	9	52	5	3	1	—	—	—
	$ 882	$ 762	$ 120	$ 114	$ 11	$ 9	$ 6	$ 5	$ 5	$ 72

(1) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.

(2) Amortization expense excludes impairment charges related to intangible assets recognized in 2016, which totaled $92 million and are included in Impairment of Assets. See "Note 2, Asset Impairments" for further discussion.

(3) The coal contracts were recorded with a regulatory offset and the amortization does not impact earnings. Accordingly, the amortization expense for these coal contracts is excluded from table above.

(4) A gross amount of $40 million of coal contracts is related to FES. In June 2016, FES terminated a coal contract and the write-off is included in amortization expense in the table above.

(5) During 2016, FES recorded a pre-tax charge of $37 million associated with the termination of a customer contract, which is included in amortization expense in the table above.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

9. VARIABLE INTEREST ENTITIES

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

The caption "noncontrolling interest" within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own.

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):

- ***PNBV Trust*** - PNBV, a business trust established by OE in 1996, issued certain beneficial interests and notes to fund the acquisition of a portion of the bonds issued by certain owner trusts in connection with the sale and leaseback in 1987 of a portion of OE's interest in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. The beneficial ownership of PNBV includes a 3% interest by unaffiliated third parties.
- ***Ohio Securitization*** - In September 2012, the Ohio Companies created separate, wholly-owned limited liability companies (SPEs) which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges

payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. The SPEs are considered VIEs and each one is consolidated into its applicable utility. As of December 31, 2016 and December 31, 2015, $339 million and $362 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. 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 and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property. As of December 31, 2016 and December 31, 2015, $85 million and $128 million of the transition bonds were outstanding, respectively.
- ***MP and PE Environmental Funding Companies*** - The entities issued bonds of which the proceeds were used to construct environmental control facilities. The special purpose limited liability companies 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 special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2016 and December 31, 2015, $406 million and $429 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. See "Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments", for additional information regarding FEV's investment in Global Holding.

  As discussed in "Note 16, 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 had previously suspended in February 2011, 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 power purchase agreements 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 14 long-term PPAs with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

  Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated

Distribution segment to be recovered from customers. Purchased power costs related to the contract that may contain a variable interest were $108 million and $116 million, respectively, during the years ended December 31, 2016 and 2015.

- ***Sale and Leaseback Transactions*** - OE and FES have obligations that are not included on their Consolidated Balance Sheets related to the Beaver Valley Unit 2 and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, respectively, 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 December 31, 2016, OE's leasehold interest was 2.60% of Beaver Valley Unit 2 and FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

  On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Upon the completion of this transaction, NG will have obtained all of the lessor equity interests at Beaver Valley Unit 2. Therefore, upon the expiration of the Beaver Valley Unit 2 leases, NG will be the sole owner of Beaver Valley Unit 2 and entitled to 100% of the unit's output.

FES and other FE subsidiaries are exposed to losses under their applicable 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 December 31, 2016:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
		(In millions)	
FirstEnergy	$ 1,123	$ 879	$ 244
FES	$ 1,098	$ 875	$ 223

10. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

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

Level 1 - Quoted prices for identical instruments in active market

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

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

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

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

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

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

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2016, from those used as of December 31, 2015. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2016 and 2015. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	**December 31, 2016**				**December 31, 2015**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				***(In millions)***				
Corporate debt securities	$ —	$ 1,247	$ —	$ 1,247	$ —	$ 1,245	$ —	$ 1,245
Derivative assets - commodity contracts	10	200	—	210	4	224	—	228
Derivative assets - FTRs	—	—	7	7	—	—	8	8
Derivative assets - NUG contracts[(1)]	—	—	1	1	—	—	1	1
Equity securities[(2)]	925	—	—	925	576	—	—	576
Foreign government debt securities	—	78	—	78	—	75	—	75
U.S. government debt securities	—	161	—	161	—	180	—	180
U.S. state debt securities	—	246	—	246	—	246	—	246
Other[(3)]	199	123	—	322	105	212	—	317
Total assets	$ 1,134	$ 2,055	$ 8	$ 3,197	$ 685	$ 2,182	$ 9	$ 2,876
Liabilities								
Derivative liabilities - commodity contracts	$ (6)	$ (118)	$ —	$ (124)	$ (9)	$ (122)	$ —	$ (131)
Derivative liabilities - FTRs	—	—	(6)	(6)	—	—	(13)	(13)
Derivative liabilities - NUG contracts[(1)]	—	—	(108)	(108)	—	—	(137)	(137)
Total liabilities	$ (6)	$ (118)	$ (114)	$ (238)	$ (9)	$ (122)	$ (150)	$ (281)
Net assets (liabilities)[(4)]	$ 1,128	$ 1,937	$ (106)	$ 2,959	$ 676	$ 2,060	$ (141)	$ 2,595

(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 cash and short-term cash investments.

(4) Excludes $(3) million and $7 million as of December 31, 2016 and December 31, 2015, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2016 and December 31, 2015:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2015 Balance	$ 2	$ (153)	$ (151)	$ 39	$ (14)	$ 25
Unrealized gain (loss)	2	(49)	(47)	(5)	(7)	(12)
Purchases	—	—	—	22	(11)	11
Settlements	(3)	65	62	(48)	19	(29)
December 31, 2015 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

(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 December 31, 2016:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 1	Model	RTO auction clearing prices	($4.20) to $6.10	$0.80	Dollars/MWH
NUG Contracts	$ (107)	Model	Generation	400 to 2,984,000	754,000	MWH
			Regional electricity prices	$32.60 to $33.40	$32.80	Dollars/MWH

FES

Recurring Fair Value Measurements	December 31, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 726	$ —	$ 726	$ —	$ 678	$ —	$ 678
Derivative assets - commodity contracts	10	200	—	210	4	224	—	228
Derivative assets - FTRs	—	—	4	4	—	—	5	5
Equity securities[1]	634	—	—	634	378	—	—	378
Foreign government debt securities	—	58	—	58	—	59	—	59
U.S. government debt securities	—	48	—	48	—	23	—	23
U.S. state debt securities	—	3	—	3	—	4	—	4
Other[2]	2	81	—	83	—	184	—	184
Total assets	$ 646	$ 1,116	$ 4	$ 1,766	$ 382	$ 1,172	$ 5	$ 1,559
Liabilities								
Derivative liabilities - commodity contracts	$ (6)	$ (118)	$ —	$ (124)	$ (9)	$ (122)	$ —	$ (131)
Derivative liabilities - FTRs	—	—	(5)	(5)	—	—	(11)	(11)
Total liabilities	$ (6)	$ (118)	$ (5)	$ (129)	$ (9)	$ (122)	$ (11)	$ (142)
Net assets (liabilities)[3]	$ 640	$ 998	$ (1)	$ 1,637	$ 373	$ 1,050	$ (6)	$ 1,417

(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 $2 million and $1 million as of December 31, 2016 and December 31, 2015, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2016 and December 31, 2015:

	Derivative Asset	Derivative Liability	Net Asset/(Liability)
		(In millions)	
January 1, 2015 Balance	$ 27	$ (13)	$ 14
Unrealized gain (loss)	2	(5)	(3)
Purchases	9	(10)	(1)
Settlements	(33)	17	(16)
December 31, 2015 Balance	$ 5	$ (11)	$ (6)
Unrealized loss	(4)	(3)	(7)
Purchases	10	(5)	5
Settlements	(7)	14	7
December 31, 2016 Balance	$ 4	$ (5)	$ (1)

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2016:

	Fair Value, Net (In millions)		Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$	(1)	Model	RTO auction clearing prices	($4.20) to $5.30	$0.60	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.

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

AFS Securities

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

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT and nuclear fuel disposal trusts as of December 31, 2016 and December 31, 2015:

	December 31, 2016[(1)]			December 31, 2015[(2)]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt securities						
FirstEnergy	$ 1,735	$ 38	$ 1,773	$ 1,778	$ 16	$ 1,794
FES	847	27	874	801	9	810
Equity securities						
FirstEnergy	$ 822	$ 103	$ 925	$ 542	$ 34	$ 576
FES	564	70	634	354	24	378

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

(2) Excludes short-term cash investments: FirstEnergy - $157 million; FES - $139 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three years ended December 31, 2016, 2015 and 2014 were as follows:

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

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

December 31, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 2,133	$ 146	$ (75)	$ (37)	$ 96
FES	1,163	113	(54)	(33)	56

Held-To-Maturity Securities

Unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2016 and December 31, 2015 are immaterial to FirstEnergy. Investments in employee benefit trusts and equity method investments totaling $266 million as of December 31, 2016 and $255 million as of December 31, 2015, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

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

	December 31, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
FirstEnergy	$ 19,885	$ 19,829	$ 20,244	$ 21,519
FES	3,000	1,555	3,027	3,121

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2016 and December 31, 2015.

11. DERIVATIVE INSTRUMENTS

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

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

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

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

FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

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

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $12 million and $11 million as of December 31, 2016 and December 31, 2015, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments.

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 $33 million (FES $3 million) and $42 million (FES $3 million) as of December 31, 2016 and December 31, 2015, respectively. Based on current estimates, approximately $8 million of these unamortized losses is expected to be amortized to interest expense during the next twelve months.

Refer to "Note 3, Accumulated Other Comprehensive Income", for reclassifications from AOCI during the years ended December 31, 2016 and 2015.

As of December 31, 2016 and December 31, 2015, no commodity or interest rate derivatives were designated as cash flow hedges.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. As of December 31, 2016 and December 31, 2015, 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 $10 million and $20 million as of December 31, 2016 and December 31, 2015, respectively. During the next twelve months, approximately $7 million of unamortized gains are expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $10 million and $12 million during the years ended December 31, 2016 and 2015, respectively.

As of December 31, 2016 and December 31, 2015, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

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

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

As of December 31, 2016, FirstEnergy's net asset position under commodity derivative contracts was $86 million, which related to FES positions. Under these commodity derivative contracts, FES posted $52 million of collateral.

Based on commodity derivative contracts held as of December 31, 2016, an increase in commodity prices of 10% would decrease net income by approximately $29 million during the next twelve months.

NUGs

As of December 31, 2016, FirstEnergy's net liability position under NUG contracts was $107 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 December 31, 2016, FirstEnergy's net asset associated with FTRs was $1 million and FES' net liability associated with FTRs was $1 million, and FES posted $5 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of PJM that have load serving obligations.

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

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

Derivative Assets			Derivative Liabilities		
	Fair Value			Fair Value	
	December 31, 2016	December 31, 2015		December 31, 2016	December 31, 2015
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 133	$ 150	Commodity Contracts	$ (72)	$ (94)
FTRs	7	7	FTRs	(6)	(12)
	140	157		(78)	(106)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs(1)	(108)	(137)
Commodity Contracts	77	78	**Noncurrent Liabilities - Other**		
FTRs	—	1	Commodity Contracts	(52)	(37)
NUGs(1)	1	1	FTRs	—	(1)
	78	80		(160)	(175)
Derivative Assets	$ 218	$ 237	**Derivative Liabilities**	$ (238)	$ (281)

(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			Derivative Liabilities		
	Fair Value			Fair Value	
	December 31, 2016	December 31, 2015		December 31, 2016	December 31, 2015
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 133	$ 150	Commodity Contracts	$ (72)	$ (94)
FTRs	4	4	FTRs	(5)	(10)
	137	154		(77)	(104)
Deferred Charges and Other Assets - Other			**Noncurrent Liabilities - Other**		
Commodity Contracts	77	78	Commodity Contracts	(52)	(37)
FTRs	—	1	FTRs	—	(1)
	77	79		(52)	(38)
Derivative Assets	$ 214	$ 233	**Derivative Liabilities**	$ (129)	$ (142)

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

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

		Amounts Not Offset in Consolidated Balance Sheet		
December 31, 2015	**Fair Value**	**Derivative Instruments**	**Cash Collateral (Received)/Pledged**	**Net Fair Value**
		(In millions)		
Derivative Assets				
Commodity contracts	$ 228	$ (125)	$ —	$ 103
FTRs	8	(8)	—	—
NUG contracts	1	—	—	1
	$ 237	$ (133)	$ —	$ 104
Derivative Liabilities				
Commodity contracts	$ (131)	$ 125	$ 3	$ (3)
FTRs	(13)	8	5	—
NUG contracts	(137)	—	—	(137)
	$ (281)	$ 133	$ 8	$ (140)

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

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

December 31, 2015	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 228	$ (125)	$ —	$ 103
FTRs	5	(5)	—	—
	$ 233	$ (130)	$ —	$ 103
Derivative Liabilities				
Commodity contracts	$ (131)	$ 125	$ 3	$ (3)
FTRs	(11)	5	6	—
	$ (142)	$ 130	$ 9	$ (3)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of December 31, 2016:

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	18	47	(29)	MWH
FTRs	28	—	28	MWH
NUGs	3	—	3	MWH
Natural Gas	29	29	—	mmBTU

The following table summarizes the volumes associated with FES' outstanding derivative transactions as of December 31, 2016:

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	18	47	(29)	MWH
FTRs	22	—	22	MWH
Natural Gas	29	29	—	mmBTU

The effect of active derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income (Loss) during 2016, 2015 and 2014 are summarized in the following tables:

	Year Ended December 31		
	Commodity Contracts	FTRs	Total
		(In millions)	
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$ (14)	$ 5	$ (9)
Realized Gain (Loss) Reclassified to:			
Revenues	$ 210	$ 8	$ 218
Purchased Power Expense	(131)	—	(131)
Other Operating Expense	—	(35)	(35)
Fuel Expense	(8)	—	(8)

	Year Ended December 31		
	Commodity Contracts	FTRs	Total
		(In millions)	
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$ 93	$ (20)	$ 73
Realized Gain (Loss) Reclassified to:			
Revenues	$ 111	$ 50	$ 161
Purchased Power Expense	(130)	—	(130)
Other Operating Expense	—	(49)	(49)
Fuel Expense	(34)	—	(34)

	Year Ended December 31			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
		(In millions)		
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense	$ (86)	$ 22	$ —	$ (64)
Realized Gain (Loss) Reclassified to:				
Revenues	$ (6)	$ 68	$ —	$ 62
Purchased Power Expense	365	—	—	365
Other Operating Expense	—	(44)	—	(44)
Fuel Expense	(6)	—	—	(6)
Interest Expense	—	—	14	14

The effect of active derivative instruments not in a hedging relationship on FES' Consolidated Statements of Income (Loss) during 2016, 2015 and 2014 are summarized in the following tables:

	Year Ended December 31		
	Commodity Contracts	**FTRs**	**Total**
		(In millions)	
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$ (14)	$ 5	$ (9)
Realized Gain (Loss) Reclassified to:			
Revenues	$ 210	$ 8	$ 218
Purchased Power Expense	(131)	—	(131)
Other Operating Expense	—	(35)	(35)

	Year Ended December 31		
	Commodity Contracts	**FTRs**	**Total**
		(In millions)	
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$ 93	$ (19)	$ 74
Realized Gain (Loss) Reclassified to:			
Revenues	$ 111	$ 49	$ 160
Purchased Power Expense	(130)	—	(130)
Other Operating Expense	—	(49)	(49)

	Year Ended December 31		
	Commodity Contracts	**FTRs**	**Total**
		(In millions)	
2014			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense	$ (86)	$ 21	$ (65)
Realized Gain (Loss) Reclassified to:			
Revenues	$ (6)	$ 67	$ 61
Purchased Power Expense	365	—	365
Other Operating Expense	—	(43)	(43)

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during 2016 and 2015. Changes in the value of these contracts are deferred for future recovery from (or credit to) customers:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Year Ended December 31 NUGs	Regulated FTRs	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2016	$ (136)	$ 1	$ (135)
Unrealized loss	(15)	(3)	(18)
Purchases	—	4	4
Settlements	44	—	44
Outstanding net asset (liability) as of December 31, 2016	$ (107)	$ 2	$ (105)
Outstanding net asset (liability) as of January 1, 2015	$ (151)	$ 11	$ (140)
Unrealized loss	(47)	(9)	(56)
Purchases	—	12	12
Settlements	62	(13)	49
Outstanding net asset (liability) as of December 31, 2015	$ (136)	$ 1	$ (135)

12. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2016, FirstEnergy had an accumulated deficit of $4.5 billion. Dividends declared in 2016 and 2015 were $1.44 per share, which included dividends of $0.36 per share paid in the first, second, third and fourth quarters. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors. On January 19, 2017 the Board of Directors declared a quarterly dividend of $0.36 per share to be paid from other paid-in-capital in the first quarter of 2017.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to their respective parents from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 45%. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy’s subsidiaries’ abilities to pay cash dividends to FirstEnergy as of December 31, 2016.

Stock Issuance

On December 13, 2016, FE contributed 16,097,875 newly issued shares of its common stock to its qualified pension plan in a private placement transaction. These shares were valued at approximately $500 million in the aggregate, and were issued to satisfy a portion of FirstEnergy’s future pension funding obligations. An independent fiduciary was retained to manage and liquidate the stock over time at its discretion.

FE issued approximately 2.7 million shares of common stock in 2016 and 2.5 million shares of common stock in 2015 and 2014 to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan and certain share-based benefit plans.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2016, as follows:

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

As of December 31, 2016, and 2015, there were no preferred or preference shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy and FES as of December 31, 2016 and 2015:

	As of December 31, 2016		As of December 31	
(Dollar amounts in millions)	Maturity Date	Interest Rate	2016	2015
FirstEnergy:				
FMBs	2017 - 2056	3.340% - 9.740%	$ 3,328	$ 3,269
Secured notes - fixed rate	2017 - 2037	0.679% - 12.000%	2,295	2,096
Secured notes - variable rate	2017	3.500%	10	2
Total secured notes			2,305	2,098
Unsecured notes - fixed rate	2017 - 2045	2.150% - 7.700%	13,058	13,580
Unsecured notes - variable rate	2021	2.430%	1,200	1,292
Total unsecured notes			14,258	14,872
Capital lease obligations			104	132
Unamortized debt discounts			(25)	(18)
Unamortized debt issuance costs			(87)	(93)
Unamortized fair value adjustments			(6)	5
Currently payable long-term debt			(1,685)	(1,166)
Total long-term debt and other long-term obligations			$ 18,192	$ 19,099
FES:				
Secured notes - fixed rate	2017 - 2022	4.250% - 12.000%	$ 617	$ 340
Secured notes - variable rate	2017	3.500%	10	2
Total secured notes			627	342
Unsecured notes - fixed rate	2017 - 2039	2.150% - 6.800%	2,373	2,593
Unsecured notes - variable rate			—	92
Total unsecured notes			2,373	2,685
Capital lease obligations			8	13
Unamortized debt discounts			(1)	(1)
Unamortized debt issuance costs			(15)	(17)
Currently payable long-term debt			(179)	(512)
Total long-term debt and other long-term obligations			$ 2,813	$ 2,510

On May 1, 2016, JCP&L repaid $300 million of 5.625% senior unsecured notes at maturity.

On June 1 and July 1 of 2016, NG repurchased approximately $225 million and $60 million, respectively of PCRBs, which were subject to a mandatory put on such date. On August 15, 2016, NG remarketed the approximately $285 million of PCRBs secured by FMBs with a fixed interest rate of 4.375% and mandatory put dates ranging from June 1, 2022 to July 1, 2022.

On July 11, 2016, Penn issued $50 million of 4.24% FMBs due 2056. Proceeds received from the issuance of the FMBs were used: (i) to fund capital expenditures; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

On August 15, 2016, WP repaid $145 million of 5.875% FMBs at maturity. Also, on September 23, 2016, WP agreed to sell $475 million of new 3.84% FMBs due 2046 ($100 million), 4.09% FMBs due 2047 ($100 million) and 4.14% FMBs due 2047 ($275 million). On December 15, 2016, WP issued the $100 million of 3.84% FMBs due 2046. The remaining sales are expected to settle on September 15, 2017 and December 15, 2017, respectively. Proceeds to be received from the issuances of the FMBs were or are, as the case may be, expected to be used: (i) for general corporate purposes; and (ii) to repay a portion of WP's $275 million of 5.95% FMBs that mature on December 15, 2017.

On August 15, 2016, FG remarketed approximately $86 million of PCRBs secured by FMBs with fixed interest rates ranging from 4.25% to 4.50% and mandatory put dates ranging from May 1, 2021 to June 1, 2021.

On September 15, 2016, FG remarketed $100 million of PCRBs secured by FMBs with a fixed interest rate of 4.25% and a mandatory put of September 15, 2021.

On September 15 and 30, 2016, respectively, FG retired an aggregate of $12 million of PCRBs with original maturity dates in 2018 and 2029.

On October 17, 2016, PE issued $155 million of 3.89% FMBs due 2046. Proceeds received from the issuance were used: (i) to repay short-term borrowings incurred to repay PE's $100 million of 5.80% FMBs that matured on October 15, 2016; and (ii) for general corporate purposes.

See "Note 7, Leases", for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. As of December 31, 2016 and 2015, $406 million and $429 million of environmental control bonds were outstanding, respectively.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include transition bonds issued by JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. The proceeds were used to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. As of December 31, 2016 and 2015, $85 million and $128 million of the transition bonds were outstanding, respectively.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. As of December 31, 2016 and 2015, $339 million and $362 million of the phase-in recovery bonds were outstanding, respectively.

See "Note 9, Variable Interest Entities" for additional information on securitized bonds.

Other Long-term Debt

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

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2016, the sinking fund requirement for all FMBs issued under the various mortgage indentures was zero.

In 2016, FG remarketed $86 million of fixed rate PCRBs and retired $12 million of variable interest rate PCRBs, which resulted in the elimination of LOCs related to $92 million of variable interest rate PCRBs that are no longer outstanding.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2016. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

Year	FirstEnergy	FES
	(In millions)	
2017	$ 1,641	$ 163
2018	1,702	516
2019	2,266	478
2020	1,231	667
2021	832	774

Certain PCRBs allow bondholders to tender their PCRBs for mandatory purchase prior to maturity. The following table classifies these PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs.

Year	FirstEnergy	FES
	(In millions)	
2017	$ 130	$ 130
2018	375	375
2019	232	232
2020	490	490
2021	342	342

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FG is entitled to a credit against its obligation to repay those bonds. FG pays annual fees based on the amounts of the LOCs to the issuing bank and is obligated to reimburse the bank for any drawings thereunder.

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2016, FirstEnergy and FES remain in compliance with all debt covenant provisions.

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

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

On December 6, 2016, FE and certain subsidiaries entered into new five-year syndicated credit facilities available through December 6, 2021, and concurrently terminated existing syndicated credit facilities that were to expire March 31, 2019, as follows:

- FE and the Utilities entered into a new $4 billion revolving credit facility, which represents an increase of $500 million over the existing $3.5 billion facility it replaced,
- FET and its subsidiaries entered into a $1 billion revolving credit facility, which replaced their existing $1 billion facility, and FES and AE Supply terminated their unsecured $1.5 billion credit facility (commitments of $900 million and $600

million for FES and AE Supply, respectively) and FES entered into a new, two-year secured credit facility with FE in which FE provided 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 other bonds as designated in writing to FE. In connection with the cancellation of the prior FES/AE Supply facility and entry into the new FES secured facility with FE, certain commitments and amendments associated with shared services and operational matters were made including, without limitation, as follows: (i) FE reaffirmed its obligations under the Intercompany Tax Allocation Agreement, and (ii) amendments to the Service Agreement by and among FESC, FES, FG and NG, to prevent termination until the earlier of December 31, 2018, or a change in control of FES or its subsidiaries.

FE, the Utilities and FET and its subsidiaries may use borrowings under their new facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. FES expects to use its new facility with FE to conduct its ordinary course of business in lieu of borrowing under the unregulated money pool. The new facility matures on December 31, 2018, and is secured by FMBs issued by FG ($250 million) and NG ($450 million).

Under the terms of the new FE and FET credit facilities, each borrower is required to maintain a consolidated debt to total capitalization ratio, as defined, of no more than 0.65 to 1.00, or in the case of FET, 0.75 to 1.00. For purposes of calculating its ratio, FE is permitted certain adjustments to total capitalization including (i) an exclusion for certain previously incurred after-tax, non-cash write-downs and non-cash charges of approximately $2.75 billion and (ii) a new exclusion for additional after-tax, non-cash write-downs and non-cash charges up to $5.5 billion related to asset impairments attributable to the power generation assets owned by FES, AE Supply and each of their subsidiaries. Additionally, under the new credit facility, FE is now also required to maintain a minimum interest coverage ratio of 1.75 to 1.00 until December 31, 2017, 2.00 to 1.00 beginning January 1, 2018 until December 31, 2018, 2.25 to 1.00 beginning January 1, 2019 until December 31, 2019, and 2.50 to 1.00 beginning January 1, 2020 until December 31, 2021. FE and each of the other borrowers under the new FE and FET credit facilities are currently in compliance with these financial covenants. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 described under Note 2, Asset Impairments, are excluded from FE's calculation of total capitalization pursuant to the new $5.5 billion after-tax exclusion referenced in (ii) above consistent with the terms of the facility. Other terms of the new FE credit facility exclude FES and AE Supply from the definition of “significant subsidiaries,” which removes them from FE’s covenants and defaults resulting from adverse judgments in excess of $100 million and eliminates lender approvals previously required for FES and AE Supply asset sales.

Outstanding alternate base rate advances under the new FE and FET facilities will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to the applicable borrower’s then-current senior unsecured non-credit enhanced debt ratings (reference ratings) plus the highest of (i) the “prime rate” published by the Wall Street Journal from time to time, (ii) the sum of 1/2 of 1% per annum plus the federal funds rate in effect from time to time and (iii) the LIBOR for a one-month interest period plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to the applicable borrower’s reference ratings. Swing line loans under the new FE facility will bear interest at a rate per annum equal to the sum of the alternate base rate plus an applicable margin determined by reference to the applicable borrower’s reference ratings. Changes in reference ratings of a borrower would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

FirstEnergy had $2,675 million and $1,708 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FirstEnergy’s available liquidity from external sources as of January 31, 2017 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	December 2021	$ 4,000	$ 1,341
FET[(2)]	Revolving	December 2021	1,000	1,000
		Subtotal	$ 5,000	$ 2,341
		Cash	—	308
		Total	$ 5,000	$ 2,649

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

FES had $101 million (payable to AE Supply) and $8 million of short-term borrowings as of December 31, 2016 and 2015, respectively. FES' available liquidity as of January 31, 2017 was as follows:

Type	Commitment	Available Liquidity
	(In millions)	
Two-year secured credit facility with FE	$ 500	$ 500
Cash	—	2
	$ 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 December 31, 2016:

Borrower	Revolving Credit Facility Sub-Limits	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FE	$ 4,000	$ — (1)
FET	1,000	— (1)
OE	500	500 (2)
CEI	500	500 (2)
TE	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)(3)

(1) No limitations.

(2) Excluding amounts which may be borrowed under the regulated companies' money pool.

(3) Pending regulatory approval, as discussed under "FERC Matters" below.

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

As of December 31, 2016, 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. In the case of FE, the impairment charges recognized in the fourth quarter of 2016 disclosed in "Note 2. Asset Impairments" above are excluded from FE's calculation of total capitalization pursuant to the new exclusion referenced in (ii) above consistent with the terms of the facility.

Term Loans

On December 6, 2016, FE terminated its existing $1 billion and $200 million term loan credit agreements and entered into a new $1.2 billion five-year syndicated term loan credit agreement. The term loan contains covenants and other terms and conditions substantially similar to those of the FE revolving credit facility described above, including a consolidated debt to total capitalization ratio and minimum interest coverage ratio requirement.

The initial borrowing under the new $1.2 billion FE 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. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE’s reference ratings plus the highest of (i) the administrative agent’s publicly-announced “prime rate”, (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE’s reference ratings. Changes in FE’s reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

On February 16, 2017, FE entered into two separate $125 million three-year term loan credit agreements with Bank of America, N.A. and The Bank of Nova Scotia, respectively, the proceeds of which were used to reduce short-term debt. The terms and conditions of these new credit agreements are substantially similar to the December 6, 2016, $1.2 billion five-year syndicated term loan credit agreement.

As of December 31, 2016, 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 its term loan.

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 2016 was 0.69% per annum for the regulated companies’ money pool and 2.02% per annum for the unregulated companies’ money pool.

As discussed above, FES expects to use its new $500 million secured credit facility with FE in lieu of borrowing under the unregulated companies' money pool. In addition, a separate money pool for use by FES, its subsidiaries and FENOC is expected to be established in the first quarter of 2017 at which time those companies will no longer have access to the unregulated companies' money pool. As of January 31, 2017, FES, its subsidiaries and FENOC had no borrowings in the aggregate under the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2016 and 2015, were as follows:

	2016	2015
FirstEnergy	2.47%	2.16%

14. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities, which total $713 million, as of December 31, 2016. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2016 and 2015 were as follows:

	2016	2015
	(In millions)	
FirstEnergy	$ 2,514	$ 2,282
FES	$ 1,552	$ 1,327

The following table summarizes the changes to the ARO balances during 2016 and 2015:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2015	$ 1,387	$ 841
Liabilities settled	(13)	(8)
Accretion	92	55
Revisions in estimated cash flows	(56)	(57)
Balance, December 31, 2015	$ 1,410	$ 831
Liabilities settled	(27)	(18)
Accretion	95	56
Liabilities Incurred	4	32
Balance, December 31, 2016	$ 1,482	$ 901

During 2016, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in Perry Unit 1, OE transferred the ARO (included within the FES liabilities incurred above) and related NDT assets associated with the leasehold interest to NG with the difference of $28 million credited to the common stock of FES. As of June 30, 2016, NG owns 100% of Perry Unit 1.

During 2015, FE and FES reduced its ARO by $57 million based on the results of decommissioning cost studies for the Davis-Besse and Perry nuclear generating stations.

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.

15. REGULATORY MATTERS

STATE REGULATION

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

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, 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 set in PE's plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The costs of the 2015-2017 plan are expected to be approximately $70 million, of which $43 million was incurred through December 31, 2016. 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.

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 include 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 (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L filed to participate as a respondent in that proceeding. Briefing has been completed. The oral argument was held on October 25, 2016.

On April 28, 2016, JCP&L filed tariffs with the NJBPU proposing a general rate increase associated with its distribution operations 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. The filing requested approval to increase annual operating revenues by approximately $142.1 million based upon a hybrid test year for the twelve months ending June 30, 2016. On November 30, 2016, JCP&L submitted to the ALJ a Stipulation of Settlement achieved with all the intervening parties providing for an annual $80 million distribution revenue increase, effective January 1, 2017. The ALJ filed an Initial Decision concluding that the Stipulation of Settlement should be approved, and the NJBPU approved the Stipulation of Settlement on December 12, 2016. As part of the Stipulation of Settlement the intervening parties agreed that JCP&L can accelerate the amortization of the 2012 major storm expenses (approximately $19 million annually) that are recovered through the SRC to achieve full recovery by December 31, 2019. On November 23, 2016, JCP&L filed an Amendment to its January 15, 2016 SRC Filing with the NJBPU, requesting that JCP&L be able to accelerate the amortization of the 2012 major storm expenses as agreed to in the Stipulation of Settlement, and a Stipulation of Settlement with NJBPU Staff and the Division of Rate Counsel regarding the SRC Filing was filed on December 27, 2016. The NJBPU approved this Stipulation of Settlement at the January 25, 2017 public meeting.

OHIO

The Ohio Companies currently operate under an ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO’s Opinions and Orders issued on March 31, 2016 and 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 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 approximately $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 the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs, an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016), a goal across FirstEnergy to reduce CO2 emissions by 90% below 2005 levels by 2045, and contributions, totaling $51 million, to fund energy conservation programs, economic development and job retention in the Ohio Companies’ service territory, and a fuel-fund in each of the Ohio Companies’ service territories to assist low-income customers, and to establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On April 29, 2016 and May 2, 2016, several parties, including the Ohio Companies, filed applications for rehearing on the Ohio Companies' ESP IV with the PUCO. On September 6, 2016, while the applications for rehearing were still pending before the PUCO, the OCC and NOAC filed a notice of appeal with the Ohio Supreme Court appealing various PUCO and Attorney Examiner Entries on the parties' applications for rehearing. On September 16, 2016, the Ohio Companies intervened and filed a motion to dismiss the appeal. The PUCO resolved such applications for rehearing in the October 12, 2016 Opinion and Order. The OCC and NOAC appeal remains pending before the Ohio Supreme Court.

On November 10, 2016 and November 14, 2016, several parties, including the Ohio Companies, filed additional applications for rehearing on 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 were required to implement energy efficiency programs that achieved a total annual energy savings of 1,990 GWHs and total peak demand reduction of 486 MWs in 2015. On May 12, 2016, the Ohio Companies filed their Energy Efficiency and Peak Demand Reduction Program Status Report indicating compliance with their 2015 statutory benchmarks. In 2016, the Ohio Companies estimated the annual energy savings target and peak demand reduction target will be comparable to the 2015 targets due to the energy efficiency requirements under SB310, which amended ORC 4928.66 to freeze the energy efficiency and peak demand reduction benchmarks for 2015 and 2016. 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.

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 2015 and 2016 that remain at the 2014 level. 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. The matter is not yet scheduled for oral argument.

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. The matter remains pending before the PUCO.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3-, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

Following the expiration of the current DSPs, the Pennsylvania Companies will operate under new 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 new 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. In addition, the new DSPs include modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans were effective through May 31, 2016. Total Phase II costs of these plans were $174 million and are recoverable through the Pennsylvania Companies' reconcilable EE&C riders. 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- $88.34 million; PN- $56.74 million; Penn- $56.35 million; and ME- $43.44 million. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. On June 9, 2016, the PPUC approved the Pennsylvania Companies' DSIC riders to be effective July 1, 2016, subject to hearings and refund or reallocation among customers. The four proceedings were consolidated by the ALJ. On January 19, 2017, in the PPUC's order approving the Pennsylvania Companies' general rate cases, discussed below, the PPUC referred the issue of whether ADIT should be included in DSIC calculations to the consolidated DSIC proceeding. On February 2, 2017, the parties to the consolidated DSIC proceeding submitted a Joint Settlement to the ALJ to resolve issues referred to by the ALJ in its June 9, 2016 Order, subject to PPUC approval, and would not result in any refund or reallocation among customers. The ADIT issue will be considered separately from the issues resolved in the Joint Settlement Petition of February 2, 2017, and is the sole issue to be litigated in the consolidated DSIC proceeding through a procedural schedule to be determined by the ALJ.

On April 28, 2016, each of the Pennsylvania Companies filed tariffs with the PPUC proposing general rate increases associated with their distribution operations to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements. The filings requested approval to increase annual operating revenues by approximately $140.2 million at ME, $158.8 million at PN, $42.0 million at Penn, and $98.2 million at WP, based upon fully projected future test years for the twelve months ending December 31, 2017 at each of the Pennsylvania Companies. As a result of the enactment of Act 40 of 2016 that terminated the practice of making a CTA when calculating a utility's federal income taxes for ratemaking purposes, the Pennsylvania Companies submitted supplemental testimony on July 7, 2016, that quantified the value of the elimination of the CTA and outlined their plan for investing 50 percent of that amount in rate base eligible equipment as required by the new law. Formal settlement agreements for each of the Pennsylvania Companies were filed on October 14, 2016, which proposed increases in annual operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP. One item related to the calculation of DSIC rates was reserved for briefing, with briefs filed by two parties. On November 21, 2016, the ALJ issued a Recommended Decision recommending approval of the settlement agreements and dismissal of the one issue reserved for briefing. Exceptions to that Recommended Decision were filed by one party on December 1, 2016, and reply exceptions were filed by the Pennsylvania Companies on December 8, 2016. On January 19, 2017, the PPUC issued an order approving the settlements and referring the reserved issue to the Pennsylvania Companies' consolidated DSIC proceeding. On February 3, 2017, one party filed a Petition for Reconsideration or Clarification relating to the limited issue of the scope of the record to be transferred to the DSIC proceeding, discussed above. The outcome of this request will not affect the new rates which took effect on January 27, 2017.

WEST VIRGINIA

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

On March 31, 2016, MP and PE filed with the WVPSC seeking approval of their Phase II energy efficiency program including three MP and PE energy efficiency programs to meet their Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, as agreed to by MP and PE, and approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of the 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. A unanimous settlement was reached by the parties on all issues and presented to the WVPSC on August 18, 2016. An order approving the settlement in full without modification was issued by the WVPSC on September 23, 2016. The Phase II program began initial implementation in November 2016.

The Staff of the WVPSC and the Consumer Advocate Division filed a Show Cause petition on August 5, 2016, requesting that the WVPSC order MP and PE to file and implement RFPs for all future capacity and energy requirements above 100 MWs and that they comply with an RFP settlement provision from the Harrison power station acquisition. MP and PE filed a timely response to the petition arguing for dismissal on September 7, 2016. On October 17, 2016, the WVPSC denied the petition filed by the Staff of the WVPSC and the Consumer Advocate Division and dismissed the case.

On August 16, 2016, MP and PE filed their annual ENEC case proposing an annual increase in rates of approximately $65 million effective January 1, 2017, which is a 4.7% increase over existing rates. The increase is comprised of a $119 million under-recovered balance as of June 30, 2016, and a projected $54 million over-recovery for the 2017 rate effective period. The parties reached a unanimous settlement providing for a $25 million increase beginning January 1, 2017 and keeping ENEC rates at the same level for a two year period. The settlement was presented to the WVPSC at a hearing on November 9, 2016. On December 9, 2016, the WVPSC approved the settlement as submitted.

On August 22, 2016, MP and PE filed an application for approval of a modernization and improvement plan for coal-fired boilers at electric power plants and cost-recovery surcharge proposing an approximate $6.9 million annual increase in rates to be effective May 1, 2017, which is a 0.5% increase over existing rates. The filing is in response to recent legislation by the West Virginia Legislature permitting accelerated recovery of costs related to modernizing and improving coal-fired boilers, including costs related to meeting environmental requirements and reducing emissions. The filing was supplemented on September 28, 2016, to add two additional projects, resulting in an approximate $7.4 million annual increase in rates. The Staff of the WVPSC filed a motion to dismiss the case arguing the new statute was not meant to recover these types of projects, but the WVPSC set the case for hearing for February 21-23, 2017. As part of the annual ENEC settlement described above, the parties agreed that MP and PE will increase ENEC rates to provide for a return of and on MATS/CSPR capital costs incurred during 2016-2017. Accordingly, MP and PE withdrew this case as part of the ENEC approval.

On December 30, 2015, MP 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 finding that IRPs are informational and that it must not approve or disapprove the IRP. MP issued a RFP to address its generation shortfall identified in the IRP on December 16, 2016 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. MP expects to execute definitive agreements with selected respondent(s) and file the appropriate applications with the WVPSC and FERC by March 15, 2017.

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 its subsidiaries, AE Supply, FENOC, ATSI 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.

On January 27, 2016, certain parties filed a complaint with FERC against FES and the Ohio Companies requesting FERC review the ESP IV PPA under Section 205 of the FPA. On April 27, 2016, FERC issued an order granting the complaint, prohibiting any transactions under the ESP IV PPA pending authorization by FERC, and directing FES to submit the ESP IV PPA for FERC review if the parties desired to transact under the agreement. FES and the Ohio Companies did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA. FES and the Ohio Companies subsequently advised FERC of this course of action. On January 19, 2017, FERC issued an order accepting compliance filings by FES, its subsidiaries, and the Ohio Companies updating their respective market-based rate tariffs to clarify that affiliate sales restrictions under the tariffs apply to the ESP IV PPA, and also that the ESP IV PPA does not affect certain other waivers of its affiliate restrictions rules FERC previously granted these entities.

On May 2, 2016, the Ohio Companies filed an Application for Rehearing with the PUCO that included a modified Rider RRS proposal that did not involve a FERC-jurisdictional PPA. Several parties subsequently filed protests and comments with FERC alleging, among other things, that the modified Rider RRS constituted a "virtual PPA". FERC rejected these protests in its January 19, 2017 order accepting the updated market-based rate tariffs of FES, its subsidiaries, and the Ohio Companies discussed below.

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. The PJM TOs responded to the protesting parties' various pleadings and motions. 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. On July 15, 2016, the MISO TOs filed an appeal of FERC's orders with the Sixth Circuit. On November 16, 2016, the Sixth Circuit granted FirstEnergy's intervention on behalf of ATSI, the Ohio Companies, and PP, and a procedural schedule has been established. 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.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. In February and August 2016, respectively, FERC and the PPUC granted the authorization for PN and ME to contribute their transmission assets to MAIT at book value, together with the approval of related intercompany agreements, including MAIT’s participation in FirstEnergy’s regulated companies' money pool. FirstEnergy subsequently withdrew its request for authorization before the NJBPU to also transfer JCP&L's transmission assets to MAIT.

On October 28, 2016, MAIT and PJM submitted joint applications to FERC requesting authorization for (i) PJM to update its Tariff and other agreements to reflect the withdrawal of ME and PN as TOs, and (ii) MAIT to become a participating PJM TO. FERC approval would authorize MAIT to be a PJM TO, and would permit PJM to implement MAIT's formula rate on MAIT's behalf. On January 26, 2017, FERC issued an order granting the requested authorization and MAIT now owns and operates the transmission assets of ME and PN. On January 31, 2017, MAIT issued membership interests to FET, PN and ME in exchange for their respective cash and asset contributions.

On October 14 and 28, 2016, MAIT submitted applications to FERC requesting authorization to issue equity, short-term debt, and long-term debt. On December 8, 2016, FERC issued an order authorizing the application to issue equity as requested. MAIT is expected to issue short-term debt and participate in the FirstEnergy regulated companies' money pool for working capital, to fund day-to-day operations, and for other general corporate purposes. Over the long-term, MAIT is expected to issue long-term debt to support capital investment and to establish an actual capital structure for ratemaking purposes. On February 3, 2017, MAIT amended its debt authorization application to provide additional information regarding recovery of its investment and debt costs. MAIT requested an order from FERC on the debt authorization by February 28, 2017. FERC's order remains pending.

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. On November 30, 2016, 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. MAIT filed a response to the protests on December 12, 2016. On December 28, 2016, FERC Staff issued a deficiency letter with respect to the PJM-related application, which also requested additional information regarding MAIT's proposed formula rate. As a result of the deficiency letter, FERC's order on the formula rate remains pending. MAIT responded to FERC Staff's request on January 10, 2017, and requested that FERC issue an order approving the formula rate immediately after consummation of the transaction, which occurred on January 31, 2017. On February 15, 2017, MAIT filed a further answer to certain protesting parties' comments on its January 10th deficiency letter response.

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. On November 18, 2016, 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 December 5, 2016, JCP&L filed a response to the protest. On December 28, 2016, FERC Staff issued a deficiency letter requesting additional information regarding JCP&L's proposed transmission rate. As a result of the deficiency letter, FERC's order on the rate remains pending. JCP&L responded to FERC Staff's request on January 10, 2017, and requested that FERC issue an order approving the formula rate effective January 1, 2017. On February 15, 2017, JCP&L filed a further answer to certain protesting parties' comments on its January 10th deficiency letter response.

Competitive Generation Asset Sale

On February 17, 2017, AE Supply and AGC submitted filings with FERC for authorization to sell four natural gas generating plants and an undivided ownership interest in Bath County to Aspen for approximately $925 million, in an all cash transaction. The four natural gas plants are: Springdale Generating Facility (638 MWs), Chambersburg Generating Facility (88 MWs), Gans Generating Facility (88 MWs), and Hunlock Creek (45 MWs). The 713 MW ownership interest in Bath County represents AE Supply's indirect ownership interest in the power station. The FERC applications include a request for authorization to transfer the hydroelectric license under Part I of the FPA, and a request for authorization to transfer the FERC-jurisdictional facilities associated with the hydroelectric projects under Part II of the FPA. Additional filings have been submitted to FERC for the purpose of amending affected FERC-jurisdictional rates and implementing the transaction once regulatory approval is obtained. The VSCC also must approve the sale of the Bath County Hydro interest. The parties expect to close the transaction in the third quarter of 2017, subject to satisfaction of various customary and other closing conditions, including without limitation, receipt of regulatory approvals and third party consents. See "Note 22. Subsequent Events" below for additional information regarding the transaction.

California Claims Litigation

Since 2002, AE Supply has been involved in litigation and claims based on its power sales to the California Energy Resource Scheduling division of the CDWR during 2001-2003. This litigation and claims are related to litigation and claims advanced by the California Attorney General and certain California utilities regarding alleged market manipulation of the wholesale energy markets in California during the 2000-2001 period. AE Supply negotiated a settlement with the California Attorney General and the California utilities and, on August 24, 2016, filed the settlement agreement for FERC approval. The settlement calls for AE Supply to pay, without admission of any liability, $3.6 million in settlement in principle of all remaining claims that are based on AE Supply's power sales in the western energy markets during the 2001-2003 time period. On October 27, 2016 FERC approved this settlement, and AE Supply paid the settlement shortly thereafter.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. 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 settlement proceedings and a hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. On January 19, 2017, FERC issued an order accepting the initial decision in part and denying it in part. Relying on its revised ROE methodology described in FERC Opinion No. 531, FERC reduced the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017. Additionally, FERC allowed recovery of costs related to land acquisitions and dispositions and legal expenses, but disallowed certain costs related to advertising and outreach. PATH filed a request for rehearing with FERC on February 20, 2017, seeking recovery of the advertising and outreach costs and requesting that the ROE be reset to 10.4%.

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.

16. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.3 billion (assuming 102 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (NG-$506 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, NG purchases insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. NG is a Member Insured of NEIL, which provides coverage for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. NG, as the Member Insured and each entity with an insurable interest, purchases policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.40 billion (NG-$1.39 billion) for replacement power costs incurred during an outage after an initial 12-week waiting period.

NG, as the Member Insured and each entity with an insurable interest, is insured under property damage insurance provided by NEIL. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. Member Insureds of NEIL pay annual premiums and are subject to retrospective premium assessments if losses exceed the accumulated funds available to the insurer. NG purchases insurance through NEIL that will pay its obligation in the event a retrospective premium call is made by NEIL, subject to the terms of the policy.

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of NG's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy’s insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of December 31, 2016, outstanding guarantees and other assurances aggregated approximately $3.3 billion, consisting of parental guarantees ($581 million), subsidiaries' guarantees ($1,933 million), other guarantees ($300 million) and other assurances ($465 million).

Of this 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 FES' power portfolio exposure as of December 31, 2016, FES has posted collateral of $190 million and AE Supply has posted collateral of $4 million. The Regulated Distribution Segment has posted collateral of $3 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining, which is the ability to secure additional collateral when needed, could be required. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of December 31, 2016:

Potential Additional Collateral Obligations	**FES**	**AE Supply**	**Regulated**	**Total**
		(In millions)		
Contractual Obligations for Additional Collateral				
At Current Credit Rating	$ 7	$ 3	$ —	$ 10
Upon Further Downgrade	—	—	48	48
Surety Bonds (Collateralized Amount)[1]	240	25	102	367
Total Exposure from Contractual Obligations	$ 247	$ 28	$ 150	$ 425

[1] Effective January 2017, FE is a guarantor for $169 million of FG surety bonds for the benefit of the PA DEP with respect to LBR.

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2016, neither FES nor AE Supply had any collateral posted with their affiliates. Moreover, a further downgrade for either FES or AE Supply would not trigger any obligations to post any such collateral.

OTHER COMMITMENTS, CONTINGENCIES AND ASSURANCES

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 FirstEnergy, 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. 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 of Delaware's CAA Section 126 petition by six months to April 7, 2017. 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. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

MATS imposes 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. FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $286 million has been spent through December 31, 2016 ($125 million at CES and $161 million at Regulated Distribution).

On August 3, 2015, FG, a 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. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. 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 liability hearing from November 28, 2016, through December 9, 2016, and, if necessary, a damages hearing is scheduled to begin on May 8, 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearing proceedings, which are scheduled to conclude February 24, 2017. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FG intends to vigorously assert its position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. Refer to the "Strategic Review of Competitive Operations" section of "Note 1, Organization and Basis of Presentation," for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

On December 22, 2016, FG, a wholly owned subsidiary of FES, received a demand for arbitration and statement of claim from BNSF and NS who 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 Plant. 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. FG intends to vigorously assert its position in this arbitration proceeding. 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. Refer to the "Strategic Review of Competitive Operations" section of "Note 1, Organization and Basis of Presentation," for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under U.S. bankruptcy laws. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced in the above arbitration proceedings, FG paid approximately $70 million in the aggregate in liquidated damages to settle delivery shortfalls in 2014 related to its deactivated plants, which approximated full liquidated damages under the agreements for such year related to the plant deactivations. Liquidated damages for the period 2015-2025 remain in dispute under both coal transportation agreements.

As to a specific coal supply agreement, AE Supply asserted termination rights effective in 2015 as a result of MATS. In response to notification of the termination, the coal supplier commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. AE Supply has filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are approximately 5.5 million tons remaining under the contract for delivery. At this time, AE Supply cannot estimate the loss or range of loss regarding the ongoing litigation with respect to this agreement.

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. Depending on the outcome 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 greenhouse gas 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 are effective on November 4, 2016. It remains unclear whether and how the results of the 2016 United States election could impact the regulation of GHG emissions at the federal and state level. 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 will 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. 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 December 31, 2016 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 $137 million have been accrued through December 31, 2016. Included in the total are accrued liabilities of approximately $89 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 loss cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2016, FirstEnergy had approximately $2.5 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 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. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As FES no longer maintains investment grade credit ratings from either S&P or Moody's, NG funded a $10 million supplemental trust in 2016 in lieu of the FES parental guarantee that would be required to support the decommissioning of the spent fuel storage facilities. The termination of the FES parental guarantee is subject to NRC review. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantees, as appropriate.

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. In addition to the $500 million credit facility with FE discussed above, FE is working with FES to establish conditional credit support on terms and conditions to be agreed upon for the $400 million FES parental support agreement that is currently in place for the benefit of NG in the event that FES is unable to provide the necessary support to NG.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 15, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

17. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, including corporate and nuclear facility operational and maintenance support, interest on affiliated company notes including the money pools and other transactions.

FirstEnergy's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements. The primary affiliated company transactions for FES during the three years ended December 31, 2016 are as follows:

FES	**2016**	**2015**	**2014**
		(In millions)	
Revenues:			
Electric sales to affiliates	$ 457	$ 664	$ 861
Other	11	14	15
Expenses:			
Purchased power from affiliates	622	353	271
Fuel	4	1	1
Support services	748	705	619
Investment Income:			
Interest income from FE	2	2	3
Interest Expense:			
Interest expense to affiliates	5	4	3
Interest expense to FE	2	3	4

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Intercompany transactions are generally settled under commercial terms within thirty days. FES purchases the entire output of the generation facilities owned by FG and NG, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are 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 are evaluating the possible termination of the PSA.

Additionally, FES and AE Supply are parties to an affiliated commodity transfer agreement in which AE Supply sells coal to FES in accordance with the terms and conditions set forth under the respective coal purchase agreements that AE Supply has with a third party. During 2016, 2015 and 2014, AE Supply sold 1.5 million, 1.2 million, and 1.7 million tons of coal to FES, respectively, at its cost of $80.4 million, $62.8 million, and $96.3 million, respectively.

FES and the Utilities are parties to an intercompany income tax allocation agreement with FE and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FE are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see "Note 6, Taxes").

18. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. 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 FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the years ended December 31, 2016, 2015, and 2014, Condensed Consolidating Balance Sheets as of December 31, 2016 and December 31, 2015, and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2016, 2015, and 2014, for the parent and guarantor and non-guarantor subsidiaries are presented below. These statements are provided as FG's parent company fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by the parent company using the equity method. Results of operations for FG and NG are, therefore, reflected in their parent company's investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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

For the Year Ended December 31, 2016	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME (LOSS)					
REVENUES	$ 4,242	$ 1,739	$ 2,004	$ (3,587)	$ 4,398
OPERATING EXPENSES:					
Fuel	—	582	198	—	780
Purchased power from affiliates	4,024	—	187	(3,587)	624
Purchased power from non-affiliates	1,020	—	—	—	1,020
Other operating expenses	310	286	632	49	1,277
Pension and OPEB mark-to-market adjustment	(1)	(4)	53	—	48
Provision for depreciation	13	120	206	(3)	336
General taxes	31	30	27	—	88
Impairment of assets	39	3,937	4,729	(83)	8,622
Total operating expenses	5,436	4,951	6,032	(3,624)	12,795
OPERATING LOSS	(1,194)	(3,212)	(4,028)	37	(8,397)
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	(4,585)	30	84	4,538	67
Miscellaneous income	4	3	—	—	7
Interest expense — affiliates	(50)	(10)	(4)	57	(7)
Interest expense — other	(55)	(105)	(44)	57	(147)
Capitalized interest	—	8	26	—	34
Total other income (expense)	(4,686)	(74)	62	4,652	(46)
LOSS BEFORE INCOME TAX BENEFITS	(5,880)	(3,286)	(3,966)	4,689	(8,443)
INCOME TAX BENEFITS	(425)	(1,169)	(1,429)	35	(2,988)
NET LOSS	$ (5,455)	$ (2,117)	$ (2,537)	$ 4,654	$ (5,455)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET LOSS	$ (5,455)	$ (2,117)	$ (2,537)	$ 4,654	$ (5,455)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(14)	(14)	—	14	(14)
Amortized gain on derivative hedges	—	—	—	—	—
Change in unrealized gain on available-for-sale securities	52	—	52	(52)	52
Other comprehensive income (loss)	38	(14)	52	(38)	38
Income taxes (benefits) on other comprehensive income (loss)	15	(5)	20	(15)	15
Other comprehensive income (loss), net of tax	23	(9)	32	(23)	23
COMPREHENSIVE LOSS	$ (5,432)	$ (2,126)	$ (2,505)	$ 4,631	$ (5,432)

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

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,824	$ 1,801	$ 2,138	$ (3,758)	$ 5,005
OPERATING EXPENSES:					
Fuel	—	679	192	—	871
Purchased power from affiliates	3,826	—	285	(3,758)	353
Purchased power from non-affiliates	1,684	—	—	—	1,684
Other operating expenses	378	273	608	49	1,308
Pension and OPEB mark-to-market adjustment	(8)	10	55	—	57
Provision for depreciation	12	124	191	(3)	324
General taxes	45	26	27	—	98
Impairment of assets	21	2	10	—	33
Total operating expenses	5,958	1,114	1,368	(3,712)	4,728
OPERATING INCOME (LOSS)	(1,134)	687	770	(46)	277
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	844	17	(5)	(870)	(14)
Miscellaneous income	1	2	—	—	3
Interest expense — affiliates	(29)	(8)	(4)	34	(7)
Interest expense — other	(52)	(104)	(49)	58	(147)
Capitalized interest	—	6	29	—	35
Total other income (expense)	764	(87)	(29)	(778)	(130)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(370)	600	741	(824)	147
INCOME TAXES (BENEFITS)	(452)	224	278	15	65
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	(9)	—	(8)	8	(9)
Other comprehensive loss	(18)	(5)	(8)	13	(18)
Income tax benefits on other comprehensive loss	(7)	(2)	(3)	5	(7)
Other comprehensive loss, net of tax	(11)	(3)	(5)	8	(11)
COMPREHENSIVE INCOME	$ 71	$ 373	$ 458	$ (831)	$ 71

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

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME (LOSS)					
REVENUES	$ 5,990	$ 1,902	$ 2,172	$ (3,920)	$ 6,144
OPERATING EXPENSES:					
Fuel	—	1,055	198	—	1,253
Purchased power from affiliates	3,920	—	271	(3,920)	271
Purchased power from non-affiliates	2,767	4	—	—	2,771
Other operating expenses	790	269	527	49	1,635
Pension and OPEB mark-to-market adjustment	19	90	188	—	297
Provision for depreciation	10	119	193	(3)	319
General taxes	72	31	25	—	128
Total operating expenses	7,578	1,568	1,402	(3,874)	6,674
OPERATING INCOME (LOSS)	(1,588)	334	770	(46)	(530)
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	791	8	61	(799)	61
Miscellaneous income	2	4	—	—	6
Interest expense — affiliates	(12)	(6)	(4)	15	(7)
Interest expense — other	(56)	(102)	(54)	60	(152)
Capitalized interest	—	4	30	—	34
Total other income (expense)	725	(92)	33	(724)	(58)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(863)	242	803	(770)	(588)
INCOME TAXES (BENEFITS)	(619)	87	298	6	(228)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(244)	155	505	(776)	(360)
Discontinued operations (net of income taxes of $8)	—	116	—	—	116
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(10)	—	—	—	(10)
Change in unrealized gain on available-for-sale securities	21	—	21	(21)	21
Other comprehensive income (loss)	5	(5)	21	(16)	5
Income taxes (benefits) on other comprehensive income (loss)	2	(2)	8	(6)	2
Other comprehensive income (loss), net of tax	3	(3)	13	(10)	3
COMPREHENSIVE INCOME (LOSS)	$ (241)	$ 268	$ 518	$ (786)	$ (241)

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:					
Accumulated deferred income tax benefits	395	1,271	883	(270)	2,279
Customer intangibles	9	—	—	—	9
Property taxes	—	12	28	—	40
Derivatives	77	—	—	—	77
Other	24	327	—	21	372
	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
Other	—	—	—	—	—
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

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	275	—	—	—	275
Affiliated companies	433	403	461	(846)	451
Other	36	4	19	—	59
Notes receivable from affiliated companies	406	1,210	805	(2,410)	11
Materials and supplies	53	204	213	—	470
Derivatives	154	—	—	—	154
Collateral	70	—	—	—	70
Prepayments and other	48	18	—	—	66
	1,475	1,841	1,498	(3,256)	1,558
PROPERTY, PLANT AND EQUIPMENT:					
In service	93	6,367	8,233	(382)	14,311
Less — Accumulated provision for depreciation	40	2,144	3,775	(194)	5,765
	53	4,223	4,458	(188)	8,546
Construction work in progress	30	249	878	—	1,157
	83	4,472	5,336	(188)	9,703
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,327	—	1,327
Investment in affiliated companies	7,452	—	—	(7,452)	—
Other	—	10	—	—	10
	7,452	10	1,327	(7,452)	1,337
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	300	16	—	(316)	—
Customer intangibles	61	—	—	—	61
Goodwill	23	—	—	—	23
Property taxes	—	12	28	—	40
Derivatives	79	—	—	—	79
Other	29	312	14	12	367
	492	340	42	(304)	570
	$ 9,502	$ 6,663	$ 8,203	$ (11,200)	$ 13,168
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ —	$ 229	$ 308	$ (25)	$ 512
Short-term borrowings-					
Affiliated companies	2,021	389	—	(2,410)	—
Other	—	8	—	—	8
Accounts payable-					
Affiliated companies	884	146	368	(856)	542
Other	21	118	—	—	139
Accrued taxes	7	93	62	(86)	76
Derivatives	103	1	—	—	104
Other	66	61	9	45	181
	3,102	1,045	747	(3,332)	1,562
CAPITALIZATION:					
Total equity	5,605	2,944	4,476	(7,420)	5,605
Long-term debt and other long-term obligations	690	2,116	840	(1,136)	2,510
	6,295	5,060	5,316	(8,556)	8,115
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	791	791
Accumulated deferred income taxes	6	—	697	(103)	600
Retirement benefits	27	305	—	—	332
Asset retirement obligations	—	191	640	—	831
Derivatives	37	1	—	—	38
Other	35	61	803	—	899
	105	558	2,140	688	3,491
	$ 9,502	$ 6,663	$ 8,203	$ (11,200)	$ 13,168

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2016	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (842)	$ 549	$ 1,103	$ (25)	$ 785
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	186	285	—	471
Short-term borrowings, net	948	94	—	(941)	101
Redemptions and Repayments-					
Long-term debt	—	(224)	(308)	25	(507)
Other	—	(6)	(2)	—	(8)
Net cash provided from (used for) financing activities	948	50	(25)	(916)	57
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(30)	(224)	(292)	—	(546)
Nuclear fuel	—	—	(232)	—	(232)
Proceeds from asset sales	9	—	—	—	9
Sales of investment securities held in trusts	—	—	717	—	717
Purchases of investment securities held in trusts	—	—	(783)	—	(783)
Cash Investments	10	—	—	—	10
Loans to affiliated companies, net	(95)	(376)	(488)	941	(18)
Other	—	1	—	—	1
Net cash used for investing activities	(106)	(599)	(1,078)	941	(842)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (637)	$ 551	$ 1,261	$ (24)	$ 1,151
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	45	296	—	341
Short-term borrowings, net	796	67	—	(863)	—
Redemptions and Repayments-					
Long-term debt	(17)	(70)	(348)	24	(411)
Short-term borrowings, net	—	—	(28)	(98)	(126)
Common stock dividend payment	(70)	—	—	—	(70)
Other	—	(5)	(1)	—	(6)
Net cash provided from (used for) financing activities	709	37	(81)	(937)	(272)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(223)	(399)	—	(627)
Nuclear fuel	—	—	(190)	—	(190)
Proceeds from asset sales	10	3	—	—	13
Sales of investment securities held in trusts	—	—	733	—	733
Purchases of investment securities held in trusts	—	—	(791)	—	(791)
Cash investments	(10)	—	—	—	(10)
Loans to affiliated companies, net	(67)	(372)	(533)	961	(11)
Other	—	4	—	—	4
Net cash used for investing activities	(72)	(588)	(1,180)	961	(879)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (600)	$ 408	$ 785	$ (22)	$ 571
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	431	447	—	878
Short-term borrowings, net	247	114	—	(361)	—
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	(1)	(269)	(568)	22	(816)
Short-term borrowings, net	—	—	(123)	(178)	(301)
Other	(1)	(12)	(2)	—	(15)
Net cash provided from (used for) financing activities	745	264	(246)	(517)	246
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8)	(169)	(662)	—	(839)
Nuclear fuel	—	—	(233)	—	(233)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	1,163	—	1,163
Purchases of investment securities held in trusts	—	—	(1,219)	—	(1,219)
Loans to affiliated companies, net	(136)	(815)	412	539	—
Other	(1)	5	—	—	4
Net cash used for investing activities	(145)	(672)	(539)	539	(817)
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

19. 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.

During the fourth quarter of 2016, FirstEnergy modified its segment reporting to reclassify the results of operations from certain transmission assets of ME, PN and JCP&L, from the Regulated Distribution segment to the Regulated Transmission segment. Costs associated with these transmission assets, which are currently included in ME, PN, and JCP&L's stated rates, will be recovered through MAIT's and JCP&L's formula rates prospectively, once approved by FERC. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2015 and 2014 have been revised to conform to the current presentation reflecting the operating activity of the identified transmission assets within Regulated Transmission.

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the 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 and TrAIL and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project. 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 "FERC Matters" below, effective January 31, 2017, MAIT includes the transmission assets of ME and PN, and JCP&L submitted applications to FERC requesting authorization to implement forward-looking formula transmission rates. Those applications are pending before FERC. Both the forward-looking and stated rates recover costs and provide a return on transmission capital investment. Under the forward-looking rates, each of ATSI's and TrAIL's 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. Except for the recovery of the PATH abandoned project regulatory asset, the segment's revenues are primarily from transmission services provided to LSEs pursuant to the PJM Tariff. 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 December 31, 2016, this business segment controlled 13,162 MWs of electric generating capacity, including, as discussed in "Note 15, Regulatory Matters", 1,572 MWs of natural gas and hydroelectric generating capacity subject to an asset purchase agreement with Aspen and the 1,300 MW Pleasants power station which was offered into MP's RFP process by AE Supply. 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 December 31, 2016, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $2.7 billion was borrowed by FE under its revolving credit facility.

Segment Financial Information

For the Years Ended December 31	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other	Reconciling Adjustments	Consolidated
			(In millions)			
2016						
External revenues	$ 9,629	$ 1,151	$ 4,070	$ —	$ (288)	$ 14,562
Internal revenues	—	—	479	—	(479)	—
Total revenues	9,629	1,151	4,549	—	(767)	14,562
Depreciation	676	187	387	63	—	1,313
Amortization of regulatory assets, net	313	7	—	—	—	320
Impairment of assets	—	—	10,665	—	—	10,665
Investment income	49	—	66	10	(41)	84
Interest expense	586	158	194	219	—	1,157
Income taxes (benefits)	375	187	(3,498)	(121)	2	(3,055)
Net income (loss)	651	331	(6,919)	(240)	—	(6,177)
Total assets	27,702	8,755	5,952	739	—	43,148
Total goodwill	5,004	614	—	—	—	5,618
Property additions	1,063	1,101	619	52	—	2,835
2015						
External revenues	$ 9,582	$ 1,054	$ 4,698	$ —	$ (308)	$ 15,026
Internal revenues	—	—	686	—	(686)	—
Total revenues	9,582	1,054	5,384	—	(994)	15,026
Depreciation	664	164	394	60	—	1,282
Amortization of regulatory assets, net	261	7	—	—	—	268
Impairment of assets	8	—	34	—	—	42
Investment income (loss)	42	—	(16)	(9)	(39)	(22)
Impairment of equity method investment	—	—	—	362	—	362
Interest expense	600	147	192	193	—	1,132
Income taxes (benefits)	325	191	50	(262)	11	315
Net income (loss)	588	328	89	(427)	—	578
Total assets	27,390	7,800	16,027	877	—	52,094
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,040	1,020	588	56	—	2,704
2014						
External revenues	$ 9,054	$ 817	$ 5,470	$ —	$ (292)	$ 15,049
Internal revenues	—	—	819	—	(819)	—
Total revenues	9,054	817	6,289	—	(1,111)	15,049
Depreciation	651	134	387	48	—	1,220
Amortization of regulatory assets, net	1	11	—	—	—	12
Investment income	56	—	54	2	(40)	72
Interest expense	603	117	197	168	(4)	1,081
Income taxes (benefits)	209	139	(223)	(178)	11	(42)
Income (loss) from continuing operations	433	255	(417)	(58)	—	213
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	433	255	(331)	(58)	—	299
Total assets	27,332	6,864	16,180	1,176	—	51,552
Total goodwill	5,092	526	800	—	—	6,418
Property additions	855	1,446	939	72	—	3,312

20. DISCONTINUED OPERATIONS

On February 12, 2014, certain of FirstEnergy's subsidiaries sold eleven hydroelectric power stations to a subsidiary of LS Power Equity Partners II, LP for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million). Pre-tax income for the hydroelectric facilities of $155 million (FES - $186 million) for the year ended December 31, 2014, was included in discontinued operations in the Consolidated Statement of Income (Loss). Included in income for discontinued operations in the year ended December 31, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million (FES - $5 million) for year ended December 31, 2014, were included in discontinued operations in the Consolidated Statement of Income (Loss).

21. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2016 and 2015.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME (LOSS)								
(In millions, except per share amounts)	**2016**				**2015**			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	$ 3,375	$ 3,917	$ 3,401	$ 3,869	$ 3,541	$ 4,123	$ 3,465	$ 3,897
Other operating expense	1,023	953	964	918	950	842	900	1,057
Pension and OPEB mark-to-market adjustment	147	—	—	—	242	—	—	—
Provision for depreciation	339	311	334	329	313	328	322	319
Impairment of assets	9,218	—	1,447	—	18	8	16	—
Operating Income (Loss)	(8,924)	861	(975)	776	236	908	554	594
Income (loss) before income taxes (benefits)	(9,185)	631	(1,219)	541	(396)	621	302	366
Income taxes (benefits)	(3,389)	251	(130)	213	(170)	226	115	144
Net Income (Loss)	(5,796)	380	(1,089)	328	(226)	395	187	222
Earnings (loss) per share of common stock-[(1)]								
Basic - Earnings (losses) Available to FirstEnergy Corp.	(13.44)	0.89	(2.56)	0.78	(0.53)	0.94	0.44	0.53
Diluted - Earnings (losses) Available to FirstEnergy Corp.	(13.44)	0.89	(2.56)	0.77	(0.53)	0.93	0.44	0.53

(1) The sum of quarterly earnings per share information may not equal annual earnings per share due to the issuance of shares throughout the year and the $500 million equity issuance in December 2016. See FirstEnergy's Consolidated Statements of Stockholders' Equity, "Note 5, Stock-Based Compensation Plans" and "Note 12, Capitalization" for additional information.

FES

CONSOLIDATED STATEMENTS OF INCOME (LOSS)								
(In millions)	**2016**				**2015**			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	$ 997	$ 1,100	$ 1,102	$ 1,199	$ 1,171	$ 1,338	$ 1,119	$ 1,377
Other operating expense	352	316	369	240	312	246	337	413
Pension and OPEB mark-to-market adjustment	48	—	—	—	57	—	—	—
Provision for depreciation	86	83	84	83	84	79	81	80
Impairment of assets	8,082	—	540	—	17	—	16	—
Operating Income (Loss)	(8,153)	101	(571)	226	25	240	—	12
Income (loss) from continuing operations before income taxes (benefits)	(8,171)	96	(581)	213	(13)	190	(25)	(5)
Income taxes (benefits)	(2,983)	56	(143)	82	1	70	(4)	(2)
Net Income (Loss)	(5,188)	40	(438)	131	(14)	120	(21)	(3)

22. SUBSEQUENT EVENTS

On January 18, 2017, AE Supply and AGC entered into an asset purchase agreement to sell four of AE Supply's natural gas generating plants in Pennsylvania and approximately 59% of AGC's interests in a Virginia hydroelectric power station to Aspen. The power stations included in the sale have a total capacity of 1,572 MWs:

- Bath County Hydro (713 MWs pumped-storage hydro) in Warm Springs, Va. (represents AE Supply's indirect interest)
- Springdale Generating Facility Units 1-5 (638 MWs natural gas) in Springdale Township, Pa.
- Chambersburg Generating Facility Units 12-13 (88 MWs natural gas) in Guildford Township, Pa.
- Gans Generating Facility Units 8-9 (88 MWs natural gas) in Springhill Township, Pa.
- Hunlock Creek (45 MWs natural gas) in Hunlock Creek, Pa.

Under the terms of the agreement, the facilities would be purchased for an all cash purchase price of approximately $925 million. The transaction is expected to close in the third quarter of 2017 subject to satisfaction of various customary and other closing conditions, including, without limitation, receipt of regulatory approvals, third party consents and the satisfaction and discharge of AE Supply's senior note indenture, under which there is approximately $305 million aggregate principal amount of indebtedness outstanding. 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. Further, the satisfaction and discharge of AE Supply's senior note indenture in connection with the closing is expected to require the payment of a “make-whole” premium calculated just prior to the redemption, which based on current interest rates is approximately $100 million. It is expected that proceeds from the sale will be invested in the unregulated money pool and may be used for the repayment of debt and general corporate purposes.

As a further condition to closing, FE will provide Aspen two limited guaranties of certain obligations of AE Supply and AGC arising under the purchase agreement. The guaranties vary in amount and scope and expire in one and three years, respectively.

On February 16, 2017, FE entered into two separate $125 million three-year term loan credit agreements with Bank of America, N.A. and The Bank of Nova Scotia, respectively, the proceeds of which were used to reduce short-term debt. The terms and conditions of these new credit agreements are substantially similar to the December 6, 2016, $1.2 billion five-year syndicated term loan credit agreement.

SHAREHOLDER SERVICES

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company, LLC (AST) is the company's Transfer Agent and Registrar. Registered shareholders wanting to transfer stock, or who need assistance or information, can send their stock certificate(s) or write to FirstEnergy Corp., c/o American Stock Transfer & Trust Company, LLC, P.O. Box 2016, New York, NY 10272-2016. Shareholders also can call toll-free at 1-800-736-3402, between 8:00 a.m. and 8:00 p.m. Eastern time, Monday through Friday. For Internet access to general shareholder and account information, visit the AST website at https://us.astfinancial.com/investpower/new_plandet.asp.

STOCK INVESTMENT PLAN

Registered shareholders and employees of the company can participate in the Stock Investment Plan. To learn more about the company's Stock Investment Plan, visit AST's website at https://us.astfinancial.com/investpower/new_plandet.asp or contact AST toll-free at 1-800-736-3402.

DIRECT DIVIDEND DEPOSIT

Registered shareholders can have their dividend payments automatically deposited to checking, savings or credit union accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact AST toll-free at 1-800-736-3402 to receive a Direct Dividend Deposit Authorization Agreement.

STOCK LISTING AND TRADING

The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

FORM 10-K ANNUAL REPORT

The Annual Report on Form 10-K, as filed with the Securities and Exchange Commission, including the financial statements and financial statement schedules, will be sent to you without charge upon written request to Ketan K. Patel, Vice President, Corporate Secretary and Chief Ethics Officer, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You also can view the Form 10-K by visiting the company's website at www.firstenergycorp.com/financialreports.

PRESORTED STD
U.S. POSTAGE
PAID
AKRON, OH
PERMIT No. 561

76 South Main Street, Akron, Ohio 44308-1890

FirstEnergy®