FIRSTENERGY CORP
Form 10-Q
July 30, 2015

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

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

For the quarterly period ended June 30, 2015

OR

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

For the transition period from ____________________ to ____________________

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer þ FirstEnergy Corp.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No þ FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF JUNE 30, 2015
FirstEnergy Corp., $0.10 par value	422,453,361
FirstEnergy Solutions Corp., no par value	7

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp. common stock.
This combined Form 10-Q is separately filed by FirstEnergy Corp. and FirstEnergy Solutions Corp. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to the other registrant, except that information relating to FirstEnergy Solutions Corp. is also attributed to FirstEnergy Corp.
FirstEnergy Web Site and Other Social Media Sites and Applications

Each of the registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through the "Investors" page of FirstEnergy's Internet web site at www.firstenergycorp.com.

These SEC filings are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post additional important information including press releases, investor presentations and notices of upcoming events, under the "Investors" section of FirstEnergy's Internet web site and recognize FirstEnergy's Internet web site as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under SEC Regulation FD. Investors may be notified of postings to the web site by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet web site or through push alerts from FirstEnergy Investor Relations apps for Apple Inc.'s iPad® and iPhone® devices, which can be installed for free at the Apple® online store. FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy's Internet web site or its Twitter® or Facebook® site, and any corresponding applications of those sites, shall not be deemed incorporated into, or to be part of, this report.
OMISSION OF CERTAIN INFORMATION
FirstEnergy Solutions Corp. meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

Forward-Looking Statements: This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "forecast," "target," "will," "intend," “believe,” "project," “estimate" 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 speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our revised sales strategy for the CES segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including but not limited to, our pending transmission rate case, the proposed transmission asset transfer, and the effectiveness of our repositioning 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 impact of the regulatory process on the pending 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 ESP IV in Ohio.
- 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, including FERC Opinion No. 531's revised ROE methodology for FERC-jurisdictional wholesale generation and transmission utility service; 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.
- 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.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on margins and asset valuations.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, proposed GHG emission and water discharge regulations and the effects of the EPA's CCR regulations, CSAPR, MATS, including our estimated costs of compliance, and CWA 316(b) water intake regulation.
- 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).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to the reliability of the transmission grid.
- The impact of other future changes to the operational status or availability of our generating units and any capacity penalties associated with outages at a given unit.
- 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.

- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- The impact of labor disruptions by our unionized workforce.
- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- 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.
- 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 previously-implemented dividend reduction, our cash flow improvement plan and our other proposed capital raising initiatives.
- 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.
- 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 material accounting policies.

- The ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- 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, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- 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 any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks associated with cyber-attacks on our electronic data centers that could compromise the information stored on our networks, including proprietary information and customer data.
- 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.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

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GLOSSARY OF TERMS

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

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011. As of January 1, 2014, AE merged with and into FirstEnergy Corp.
AESC	Allegheny Energy Service Corporation, a subsidiary of FirstEnergy Corp.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and equity method investee of MP.
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities.
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FirstEnergy License Holding Company, Inc.
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC which is the parent of ATSI, TrAIL and MAIT, and has a joint venture in PATH.
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	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 FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, 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 electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE

Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Signal Peak	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:

AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.

GLOSSARY OF TERMS, Continued

AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CCB	Coal Combustion By-Product
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CONE	Cost-of-New-Entry
CSA	Coal Sales Agreement
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EmPOWER Maryland	EmPower Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP	Electric Security Plan
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
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt

KWH	Kilowatt-hour
LBR	Little Blue Run
LMP	Locational Marginal Price
LOC	Letter of Credit

GLOSSARY OF TERMS, Continued

LSE	Load Serving Entity
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
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
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
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator, Inc.
NYPSC	New York State Public Service Commission
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal

RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPM	Reliability Pricing Model
RSS	Rich Site Summary

GLOSSARY OF TERMS, Continued

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
SEC Regulation FD	SEC Regulation Fair Disclosure
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
Third Circuit	United States Court of Appeals for the Third Circuit
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
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
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

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share amounts)	2015	2014	2015	2014
REVENUES:				
Electric utilities	$2,508	$2,256	$5,308	$4,988
Unregulated businesses	957	1,240	2,054	2,690
Total revenues*	3,465	3,496	7,362	7,678
OPERATING EXPENSES:				
Fuel	383	550	896	1,167
Purchased power	989	1,083	2,102	2,538
Other operating expenses	916	1,021	1,973	2,203
Provision for depreciation	322	302	641	596
Amortization (deferral) of regulatory assets, net	59	20	91	(8)
General taxes	242	228	511	499
Total operating expenses	2,911	3,204	6,214	6,995
OPERATING INCOME	554	292	1,148	683
OTHER INCOME (EXPENSE):				
Loss on debt redemptions	—	(1)	—	(8)
Investment income (loss)	(3)	29	14	51
Interest expense	(282)	(262)	(561)	(527)
Capitalized financing costs	33	32	67	61
Total other expense	(252)	(202)	(480)	(423)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	302	90	668	260
INCOME TAXES	115	26	259	74
INCOME FROM CONTINUING OPERATIONS	187	64	409	186
Discontinued operations (net of income taxes of $69) (Note 13)	—	—	—	86
NET INCOME	$187	$64	$409	$272
EARNINGS PER SHARE OF COMMON STOCK:				
Basic - Continuing Operations	$0.44	$0.16	$0.97	$0.45
Basic - Discontinued Operations (Note 13)	—	—	—	0.20

Basic - Net Earnings per Basic Share	$0.44	$0.16	$0.97	$0.65
Diluted - Continuing Operations	$0.44	$0.15	$0.97	$0.45
Diluted - Discontinued Operations (Note 13)	—	—	—	0.20
Diluted - Net Earnings per Diluted Share	$0.44	$0.15	$0.97	$0.65
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	422	420	422	419
Diluted	423	421	423	420
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$—	$—	$0.72	$0.72

* Includes excise tax collections of $96 million and $99 million the three months ended June 30, 2015 and 2014, respectively, and $211 million and $216 million in the six months ended June 30, 2015 and 2014, respectively.

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
NET INCOME	$187	$64	$409	$272
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(32)	(42)	(63)	(84)
Amortized (gains) losses on derivative hedges	1	(1)	2	(1)
Change in unrealized gains on available-for-sale securities	(14)	30	(10)	51
Other comprehensive loss	(45)	(13)	(71)	(34)
Income tax benefits on other comprehensive loss	(17)	(6)	(27)	(14)
Other comprehensive loss, net of tax	(28)	(7)	(44)	(20)
COMPREHENSIVE INCOME	$159	$57	$365	$252

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$94	$85
Receivables-		
Customers, net of allowance for uncollectible accounts of $62 in 2015 and $59 in 2014	1,590	1,554
Other, net of allowance for uncollectible accounts of $5 in 2015 and 2014	181	225
Materials and supplies	792	817
Prepaid taxes	235	128
Derivatives	171	159
Accumulated deferred income taxes	743	518
Collateral	141	230
Other	166	160
	4,113	3,876
PROPERTY, PLANT AND EQUIPMENT:		
In service	48,862	47,484
Less — Accumulated provision for depreciation	14,728	14,150
	34,134	33,334
Construction work in progress	2,282	2,449
	36,416	35,783
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,348	2,341
Other	886	881
	3,234	3,222
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,523	1,411
Other	1,301	1,456
	9,242	9,285
	$53,005	$52,166
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,292	$804
Short-term borrowings	2,908	1,799
Accounts payable	1,034	1,279
Accrued taxes	467	490
Accrued compensation and benefits	323	329
Derivatives	160	167
Other	605	693
	6,789	5,561
CAPITALIZATION:		
Common stockholders' equity-		
	42	42

Common stock, $0.10 par value, authorized 490,000,000 shares - 422,453,361 and 421,102,570 shares outstanding as of June 30, 2015 and December 31, 2014, respectively		
Other paid-in capital	9,895	9,847
Accumulated other comprehensive income	202	246
Retained earnings	2,391	2,285
Total common stockholders' equity	12,530	12,420
Noncontrolling interest	1	2
Total equity	12,531	12,422
Long-term debt and other long-term obligations	18,570	19,176
	31,101	31,598
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,485	7,057
Retirement benefits	3,836	3,932
Asset retirement obligations	1,411	1,387
Deferred gain on sale and leaseback transaction	807	824
Adverse power contract liability	203	217
Other	1,373	1,590
	15,115	15,007
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$53,005	$52,166

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(In millions)	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$409	$272
Adjustments to reconcile net income to net cash from operating activities-		
Income from discontinued operations (Note 13)	—	(86)
Provision for depreciation	641	596
Amortization (deferral) of regulatory assets, net	91	(8)
Nuclear fuel amortization	106	98
Amortization of debt related costs	20	28
Deferred purchased power and other costs	(45)	(47)
Deferred income taxes and investment tax credits, net	219	159
Investment impairments	24	3
Deferred costs on sale leaseback transaction, net	24	24
Amortization of customer intangibles and deferred advertising costs	11	39
Retirement benefits	(16)	(42)
Pension trust contributions	(143)	—
Commodity derivative transactions, net (Note 8)	(7)	40
Loss on debt redemptions	—	8
Lease payments on sale and leaseback transaction	(102)	(100)
Impairment of long lived assets	16	—
Changes in current assets and liabilities-		
Receivables	8	(44)
Materials and supplies	—	(50)
Prepayments and other current assets	(116)	(20)
Accounts payable	(245)	103
Accrued taxes	(23)	(159)
Accrued compensation and benefits	12	(70)
Other current liabilities	2	26
Cash collateral, net	38	(127)
Other	66	(21)
Net cash provided from operating activities	990	622
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	200	3,137
Short-term borrowings, net	1,109	—
Redemptions and Repayments-		
Long-term debt	(292)	(925)
Short-term borrowings, net	—	(1,081)
Common stock dividend payments	(303)	(302)
Other	(2)	(24)
Net cash provided from financing activities	712	805
CASH FLOWS FROM INVESTING ACTIVITIES:		

Property additions	(1,486)	(1,809)
Nuclear fuel	(97)	(58)
Proceeds from asset sales	10	394
Sales of investment securities held in trusts	819	1,164
Purchases of investment securities held in trusts	(881)	(1,221)
Asset removal costs	(67)	(47)
Other	9	8
Net cash used for investing activities	(1,693)	(1,569)
Net change in cash and cash equivalents	9	(142)
Cash and cash equivalents at beginning of period	85	218
Cash and cash equivalents at end of period	$94	$76

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

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

(In millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
STATEMENTS OF OPERATIONS				
REVENUES:				
Electric sales to non-affiliates	$914	$1,234	$1,989	$2,674
Electric sales to affiliates	157	176	412	525
Other	48	42	95	82
Total revenues	1,119	1,452	2,496	3,281
OPERATING EXPENSES:				
Fuel	191	334	421	653
Purchased power from affiliates	77	75	147	139
Purchased power from non-affiliates	392	618	935	1,647
Other operating expenses	353	468	766	920
Provision for depreciation	81	79	161	153
General taxes	25	29	54	68
Total operating expenses	1,119	1,603	2,484	3,580
OPERATING INCOME (LOSS)	—	(151)	12	(299)
OTHER INCOME (EXPENSE):				
Loss on debt redemptions	—	—	—	(5)
Investment income	1	24	14	44
Miscellaneous income	4	4	4	4
Interest expense — affiliates	(2)	(2)	(4)	(4)
Interest expense — other	(37)	(37)	(74)	(73)
Capitalized interest	9	8	18	20
Total other expense	(25)	(3)	(42)	(14)
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAX BENEFITS	(25)	(154)	(30)	(313)
INCOME TAX BENEFITS	(4)	(67)	(6)	(123)
LOSS FROM CONTINUING OPERATIONS	(21)	(87)	(24)	(190)
Discontinued operations (net of income taxes of $70) (Note 13)	—	—	—	116
NET LOSS	$(21)	$(87)	$(24)	$(74)
STATEMENTS OF COMPREHENSIVE LOSS				
NET LOSS	$(21)	$(87)	$(24)	$(74)

OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(4)	(5)	(8)	(10)
Amortized gains on derivative hedges	(1)	(3)	(2)	(5)
Change in unrealized gain on available-for-sale securities	(12)	25	(9)	44
Other comprehensive income (loss)	(17)	17	(19)	29
Income taxes (benefits) on other comprehensive income (loss)	(6)	7	(7)	11
Other comprehensive income (loss), net of tax	(11)	10	(12)	18
COMPREHENSIVE LOSS	$(32)	$(77)	$(36)	$(56)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$2
Receivables-		
Customers, net of allowance for uncollectible accounts of $16 in 2015 and $18 in 2014	325	415
Affiliated companies	403	525
Other, net of allowance for uncollectible accounts of $3 in 2015 and 2014	57	107
Notes receivable from affiliated companies	13	—
Materials and supplies	476	492
Derivatives	158	147
Collateral	140	229
Prepayments and other	139	95
	1,713	2,012
PROPERTY, PLANT AND EQUIPMENT:		
In service	13,978	13,596
Less — Accumulated provision for depreciation	5,431	5,208
	8,547	8,388
Construction work in progress	917	1,010
	9,464	9,398
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,365	1,365
Other	10	10
	1,375	1,375
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	70	78
Goodwill	23	23
Property taxes	19	41
Unamortized sale and leaseback costs	266	217
Derivatives	104	52
Other	117	114
	599	525
	$13,151	$13,310
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$683	$506
Short-term borrowings-		
Affiliated companies	—	35
Other	258	99
Accounts payable-		
Affiliated companies	297	416
Other	117	248
Accrued taxes	79	102

Derivatives	158	166
Other	163	184
	1,755	1,756
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares - 7 shares outstanding as of June 30, 2015 and December 31, 2014	3,599	3,594
Accumulated other comprehensive income	45	57
Retained earnings	1,910	1,934
Total common stockholder's equity	5,554	5,585
Long-term debt and other long-term obligations	2,359	2,608
	7,913	8,193
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	807	824
Accumulated deferred income taxes	588	511
Retirement benefits	331	324
Asset retirement obligations	850	841
Derivatives	74	14
Other	833	847
	3,483	3,361
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$13,151	$13,310

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

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

(In millions)	Six Months Ended June 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(24)	$(74)
Adjustments to reconcile net loss to net cash from operating activities-		
Income from discontinued operations (Note 13)	—	(116)
Provision for depreciation	161	153
Nuclear fuel amortization	106	98
Deferred costs on sale and leaseback transaction, net	24	24
Amortization of customer intangibles and deferred advertising costs	11	39
Deferred income taxes and investment tax credits, net	50	(23)
Investment impairments	22	3
Commodity derivative transactions, net (Note 8)	(7)	40
Lease payments on sale and leaseback transaction	(102)	(100)
Loss on debt redemptions	—	5
Impairment of long lived assets	16	—
Changes in current assets and liabilities-		
Receivables	277	550
Materials and supplies	(9)	(18)
Prepayments and other current assets	(9)	5
Accounts payable	(259)	(339)
Accrued taxes	(23)	(57)
Accrued compensation and benefits	1	(7)
Other current liabilities	17	5
Cash collateral, net	89	(117)
Other	2	12
Net cash provided from operating activities	343	83
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	—	637
Short-term borrowings, net	124	—
Equity contribution from parent	—	500
Redemptions and repayments-		
Long-term debt	(69)	(664)
Short-term borrowings, net	—	(127)
Other	(2)	(10)
Net cash provided from financing activities	53	336
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(264)	(477)
Nuclear fuel	(97)	(57)
Proceeds from asset sales	3	307
Sales of investment securities held in trusts	376	707

Purchases of investment securities held in trusts	(404)	(736)
Loans to affiliated companies, net	(13)	(168)
Other	3	5
Net cash used for investing activities	(396)	(419)
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

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

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

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

FirstEnergy Corp. 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 common stock 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 common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

FirstEnergy 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 generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy’s transmission operations include approximately 24,000 miles of lines and three regional transmission operation centers.
These interim financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and disclosures normally included in financial statements and notes prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These interim financial statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2014.

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

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 6, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, 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 share of the entity’s earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

For the three months ended June 30, 2015 and 2014, capitalized financing costs on FirstEnergy's Consolidated Statements of Income includes $14 million of allowance for equity funds used during construction for both periods and $19 million and $18 million, respectively, of capitalized interest. For the six months ended June 30, 2015 and

2014, capitalized financing costs on FirstEnergy's Consolidated Statements of Income includes $30 million and $21 million, respectively, of allowance for equity funds used during construction, and $37 million and $40 million, respectively, of capitalized interest.

During the second quarter of 2015, FES recognized an impairment of $16 million associated with certain transportation equipment. The charge is classified as a component of Other operating expenses in the Consolidated Statement of Income.

New Accounting Pronouncements

In May 2014, the FASB issued "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle 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. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. This standard is currently effective for fiscal years beginning after December 15, 2016, with no early adoption permitted, and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. In July 2015, the FASB voted to proceed with a one-year deferral of the revenue recognition standard for all entities, with early adoption as of the original effective date permitted. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In April 2015, the FASB issued, "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 guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

2. EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised.

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

(In millions, except per share amounts)	Three Months Ended June 30,		Six Months Ended June 30,	
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2015	2014	2015	2014
Income from continuing operations	$187	$64	$409	$186
Discontinued operations (Note 13)	—	—	—	86
Net income	$187	$64	$409	$272
Weighted average number of basic shares outstanding	422	420	422	419
Assumed exercise of dilutive stock options and awards(1)	1	1	1	1
Weighted average number of diluted shares outstanding	423	421	423	420
Earnings per share:				
Basic earnings per share:				
Income from continuing operations	$0.44	$0.16	$0.97	$0.45
Discontinued operations (Note 13)	—	—	—	0.20
Net earnings per basic share	$0.44	$0.16	$0.97	$0.65
Diluted earnings per share:				
Income from continuing operations	$0.44	$0.15	$0.97	$0.45
Discontinued operations (Note 13)	—	—	—	0.20
Net earnings per diluted share	$0.44	$0.15	$0.97	$0.65

(1) For both the three months ended June 30, 2015 and June 30, 2014, one million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. For the six months ended

June 30, 2015 and June 30, 2014, one million and two million shares, respectively, were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive.

3. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

In March 2015, FirstEnergy contributed $143 million to its qualified pension plan. The components of the consolidated net periodic cost (credits) for pension and OPEB (including amounts capitalized) were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Three Months Ended June 30,	2015	2014	2015	2014
	(In millions)			
Service costs	$48	$41	$1	$2
Interest costs	96	101	7	10
Expected return on plan assets	(111)	(115)	(8)	(8)
Amortization of prior service costs (credits)	2	2	(34)	(44)
Net periodic costs (credits)	$35	$29	$(34)	$(40)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Six Months Ended June 30,	2015	2014	2015	2014
	(In millions)			
Service costs	$96	$83	$2	$4
Interest costs	192	201	14	20
Expected return on plan assets	(222)	(230)	(16)	(16)
Amortization of prior service costs (credits)	4	4	(67)	(88)
Net periodic costs (credits)	$70	$58	$(67)	$(80)

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

	Pension		OPEB	
	2015	2014	2015	2014
	(In millions)			
For the Three Months Ended June 30,	$4	$4	$(5)	$(5)
For the Six Months Ended June 30,	8	8	(10)	(10)

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

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Three Months Ended June 30,	2015	2014	2015	2014
	(In millions)			
FirstEnergy	$24	$21	$(22)	$(27)
FES	4	4	(4)	(5)

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Six Months Ended June 30,	2015	2014	2015	2014
	(In millions)			
FirstEnergy	$49	$42	$(45)	$(54)
FES	8	8	(8)	(9)

4. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and six months ended June 30, 2015 and 2014, for FirstEnergy are shown in the following tables:
FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of April 1, 2015	$(36)	$28	$238	$230
Other comprehensive loss before reclassifications	—	(7)	—	(7)
Amounts reclassified from AOCI	1	(7)	(32)	(38)
Other comprehensive income (loss)	1	(14)	(32)	(45)
Income tax (benefits) on other comprehensive income (loss)	1	(5)	(13)	(17)
Net other comprehensive loss	—	(9)	(19)	(28)
AOCI Balance as of June 30, 2015	$(36)	$19	$219	$202
AOCI Balance as of April 1, 2014	$(36)	$22	$285	$271
Other comprehensive income before reclassifications	—	49	—	49
Amounts reclassified from AOCI	(1)	(19)	(42)	(62)
Other comprehensive income (loss)	(1)	30	(42)	(13)
Income tax (benefits) on other comprehensive income (loss)	(1)	11	(16)	(6)
Net other comprehensive income (loss)	—	19	(26)	(7)
AOCI Balance as of June 30, 2014	$(36)	$41	$259	$264

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2015	$(37)	$25	$258	$246
Other comprehensive income before reclassifications	—	7	—	7
Amounts reclassified from AOCI	2	(17)	(63)	(78)
Other comprehensive income (loss)	2	(10)	(63)	(71)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(24)	(27)
Net other comprehensive income (loss)	1	(6)	(39)	(44)
AOCI Balance as of June 30, 2015	$(36)	$19	$219	$202
AOCI Balance as of January 1, 2014	$(36)	$9	$311	$284

Other comprehensive income before reclassifications	—	84	—	84
Amounts reclassified from AOCI	(1)	(33)	(84)	(118)
Other comprehensive income (loss)	(1)	51	(84)	(34)
Income tax (benefits) on other comprehensive income (loss)	(1)	19	(32)	(14)
Net other comprehensive income (loss)	—	32	(52)	(20)
AOCI Balance as of June 30, 2014	$(36)	$41	$259	$264

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The following amounts were reclassified from AOCI for FirstEnergy in the three and six months ended June 30, 2015 and 2014:

Reclassifications from AOCI [2]	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014	Affected Line Item in Consolidated Statements of Income
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$(1)	$(3)	$(2)	$(5)	Other operating expenses
Long-term debt	2	2	4	4	Interest expense
	1	(1)	2	(1)	Total before taxes
	(1)	1	(1)	1	Income taxes
	$—	$—	$1	$—	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(7)	$(19)	$(17)	$(33)	Investment income (loss)
	2	7	6	12	Income taxes
	$(5)	$(12)	$(11)	$(21)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(32)	$(42)	$(63)	$(84)	[1]
	13	16	24	32	Income taxes
	$(19)	$(26)	$(39)	$(52)	Net of tax

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

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The changes in AOCI, net of tax, in the three and six months ended June 30, 2015 and 2014, for FES are shown in the following tables:
FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of April 1, 2015	$(8)	$24	$40	$56
Other comprehensive loss before reclassifications	—	(7)	—	(7)
Amounts reclassified from AOCI	(1)	(5)	(4)	(10)
Other comprehensive loss	(1)	(12)	(4)	(17)
Income tax benefits on other comprehensive loss	—	(4)	(2)	(6)
Net other comprehensive loss	(1)	(8)	(2)	(11)
AOCI Balance as of June 30, 2015	$(9)	$16	$38	$45
AOCI Balance as of April 1, 2014	$(2)	$20	$44	$62
Other comprehensive income before reclassifications	—	43	—	43
Amounts reclassified from AOCI	(3)	(18)	(5)	(26)
Other comprehensive income (loss)	(3)	25	(5)	17
Income tax (benefits) on other comprehensive income (loss)	—	9	(2)	7
Net other comprehensive income (loss)	(3)	16	(3)	10
AOCI Balance as of June 30, 2014	$(5)	$36	$41	$72

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2015	$(7)	$21	$43	$57
Other comprehensive income before reclassifications	—	6	—	6
Amounts reclassified from AOCI	(2)	(15)	(8)	(25)
Other comprehensive loss	(2)	(9)	(8)	(19)
Income tax benefits on other comprehensive loss	—	(4)	(3)	(7)
Net other comprehensive loss	(2)	(5)	(5)	(12)
AOCI Balance as of June 30, 2015	$(9)	$16	$38	$45
AOCI Balance as of January 1, 2014	$(1)	$8	$47	$54
Other comprehensive income before reclassifications	—	76	—	76
Amounts reclassified from AOCI	(5)	(32)	(10)	(47)
Other comprehensive income (loss)	(5)	44	(10)	29

Income tax (benefits) on other comprehensive income (loss)	(1)	16	(4)	11
Net other comprehensive income (loss)	(4)	28	(6)	18
AOCI Balance as of June 30, 2014	$(5)	$36	$41	$72

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The following amounts were reclassified from AOCI for FES in the three and six months ended June 30, 2015 and 2014:

Reclassifications from AOCI (2)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014	Affected Line Item in Consolidated Statements of Operations
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$(1)	$(3)	$(2)	$(5)	Other operating expenses
	—	1	—	2	Income tax benefits
	$(1)	$(2)	$(2)	$(3)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(5)	$(18)	$(15)	$(32)	Investment income
	2	6	6	11	Income tax benefits
	$(3)	$(12)	$(9)	$(21)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(4)	$(5)	$(8)	$(10)	(1)
	2	2	3	4	Income tax benefits
	$(2)	$(3)	$(5)	$(6)	Net of tax

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

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5. INCOME TAXES

FirstEnergy’s and FES’ interim effective tax rates reflect the estimated annual effective tax rates for 2015 and 2014. These tax rates are affected by estimated annual permanent items, such as AFUDC equity and other flow-through items, as well as discrete items that may occur in any given period, but are not consistent from period to period.

FirstEnergy’s effective tax rate from continuing operations for the three months ended June 30, 2015 and 2014 was 38.1% and 28.9%, respectively. The increase in the effective tax rate is primarily due to an increase in uncertain tax benefits recognized in the second quarter of 2015 and a reduction in state deferred tax liabilities recognized in the second quarter of 2014 resulting from changes in state apportionment factors.

FirstEnergy's effective tax rate from continuing operations for the six months ended June 30, 2015 and 2014 was 38.8% and 28.5%, respectively. The increase in the effective tax rate for the six month period ending June 30, 2015 is primarily due to a reduction in state deferred tax liabilities resulting from changes in state apportionment factors as well as the elimination of certain future tax liabilities associated with basis differences recognized in the first six months of 2014 and an increase in uncertain tax benefits recognized in 2015.

FES’ effective tax rate from continuing operations for the three months ended June 30, 2015 and 2014 was 16.0% and 43.5%, respectively. FES' effective tax rate from continuing operations for the six months ended June 30, 2015 and 2014 was 20.0% and 39.3%, respectively. For both periods, the decrease in the effective tax rate on pre-tax losses is primarily due to a reduction in state deferred tax liabilities recognized in the second quarter of 2014 resulting from changes in state apportionment factors and an increase in uncertain tax benefits recognized in the second quarter of 2015.

As of June 30, 2015, it is reasonably possible that approximately $10 million of unrecognized tax benefits may be resolved within the next twelve months as a result of the statute of limitations expiring, all of which would affect FirstEnergy's effective tax rate.

In January 2015, the IRS completed its examination of the 2013 federal income tax return and issued a Revenue Agent Report. For tax year 2013 there was no material impact to FirstEnergy's effective tax rate associated with this examination. Tax years 2014 and 2015 are currently under review by the IRS.

6. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses based on control and economics to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both power and benefits, 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.

VIEs included in FirstEnergy’s consolidated financial statements are: the PNBV capital trust created to refinance debt originally issued in connection with sale and leaseback transactions (PNBV trust); wholly-owned limited liability companies of the Ohio Companies created to issue phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets (Ohio Securitization); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L’s bondable stranded costs (JCP&L Securitization) and special purpose limited liability companies at MP and PE created to issue environmental control bonds that were used to construct environmental control facilities (MP and PE Environmental Funding Companies).

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 the following categories based on similar risk characteristics and significance.

PNBV Trust

FirstEnergy used debt and available funds to purchase the notes issued by PNBV for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE.

Ohio Securitization

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC as separate, wholly-owned limited liability SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property owned by the SPEs and 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 $445,000 that are recoverable through the usage-based charges. The SPEs are considered VIEs and each one is consolidated into its applicable utility. As of June 30, 2015 and December 31, 2014, $374 million and $386 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 June 30, 2015 and December 31, 2014, $150 million and $168 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. The right to collect environmental control charges is not included as an asset on FirstEnergy's consolidated balance sheets. 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 June 30, 2015 and December 31, 2014, $440 million and $450 million of the environmental control bonds were outstanding, respectively.

Mining Operations

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. FEV's equity method investment in Global Holding was $372 million as of June 30, 2015.

Previously, FEV held a 50% equity ownership in Global Holding, of which a 16.7% interest was sold in 2011. In conjunction with the 2011 sale, a subsidiary of Global Holding was given the right to put up to 2 million tons annually from the Signal Peak underground mine to FG through 2024. Such subsidiary did not exercise their right under the put for 2014. During the first quarter of 2015, such Global Holding subsidiary eliminated its right under the put in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million in the first quarter of 2015. (See Note 10, Commitments, Guarantees and Contingencies.)

PATH-WV

PATH is a 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

FirstEnergy 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 the portion of the PATH project that was to be constructed by PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 9, Regulatory Matters, for additional information on the abandonment of the PATH project.

Power Purchase 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 15 long-term power purchase agreements 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 in the entities 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 contracts that may contain a variable interest during the three months ended June 30, 2015 and 2014 were $27 million and $40 million, respectively, and $58 million and $102 million during the six months ended June 30, 2015 and 2014, respectively.

Sale and Leaseback

FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements.

As of June 30, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

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. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. Upon the completion of these transactions, NG will have obtained all of the lessor equity interests at Perry Unit 1 and Beaver Valley Unit 2.

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 June 30, 2015:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
	(In millions)		
FirstEnergy	$1,231	$958	$273
FES	1,151	929	222

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7. FAIR VALUE MEASUREMENTS

RECURRING AND NONRECURRING 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 are as follows:

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

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

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of June 30, 2015, from those used as of

December 31, 2014. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the six months ended June 30, 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	June 30, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,292	$—	$1,292	$—	$1,221	$—	$1,221
Derivative assets - commodity contracts	1	251	—	252	1	171	—	172
Derivative assets - FTRs	—	—	23	23	—	—	39	39
Derivative assets - NUG contracts(1)	—	—	1	1	—	—	2	2
Equity securities(2)	697	—	—	697	592	—	—	592
Foreign government debt securities	—	81	—	81	—	76	—	76
U.S. government debt securities	—	178	—	178	—	182	—	182
U.S. state debt securities	—	241	—	241	—	237	—	237
Other(3)	90	128	—	218	55	256	—	311
Total assets	$788	$2,171	$24	$2,983	$648	$2,143	$41	$2,832
Liabilities								
Derivative liabilities - commodity contracts	$(7)	$(214)	$—	$(221)	$(26)	$(141)	$—	$(167)
Derivative liabilities - FTRs	—	—	(13)	(13)	—	—	(14)	(14)
Derivative liabilities - NUG contracts(1)	—	—	(141)	(141)	—	—	(153)	(153)
Total liabilities	$(7)	$(214)	$(154)	$(375)	$(26)	$(141)	$(167)	$(334)
Net assets (liabilities)(4)	$781	$1,957	$(130)	$2,608	$622	$2,002	$(126)	$2,498

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

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

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

(4) Excludes $(6) million and $40 million as of June 30, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended June 30, 2015 and December 31, 2014:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2014 Balance	$20	$(222)	$(202)	$4	$(12)	$(8)
Unrealized gain (loss)	2	(2)	—	47	(1)	46
Purchases	—	—	—	26	(16)	10
Settlements	(20)	71	51	(38)	15	(23)
December 31, 2014 Balance	$2	$(153)	$(151)	$39	$(14)	$25
Unrealized gain (loss)	1	(17)	(16)	5	3	8
Purchases	—	—	—	22	(11)	11
Settlements	(2)	29	27	(43)	9	(34)
June 30, 2015 Balance	$1	$(141)	$(140)	$23	$(13)	$10

(1) Changes in the fair value of NUG contracts are generally subject to regulatory accounting treatment and do not impact earnings.

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended June 30, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$10	Model	RTO auction clearing prices	($5.10) to $9.20	$1.40	Dollars/MWH
NUG Contracts	$(140)	Model	Generation	500 to 4,317,000	833,000	MWH
			Regional electricity prices	$44.00 to $68.90	$51.00	Dollars/MWH

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FES

Recurring Fair Value Measurements	June 30, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$701	$—	$701	$—	$655	$—	$655
Derivative assets - commodity contracts	1	251	—	252	1	171	—	172
Derivative assets - FTRs	—	—	10	10	—	—	27	27
Equity securities(1)	481	—	—	481	360	—	—	360
Foreign government debt securities	—	64	—	64	—	57	—	57
U.S. government debt securities	—	27	—	27	—	46	—	46
U.S. state debt securities	—	4	—	4	—	4	—	4
Other(2)	—	87	—	87	—	199	—	199
Total assets	$482	$1,134	$10	$1,626	$361	$1,132	$27	$1,520
Liabilities								
Derivative liabilities - commodity contracts	$(7)	$(214)	$—	$(221)	$(26)	$(141)	$—	$(167)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(13)	(13)
Total liabilities	$(7)	$(214)	$(11)	$(232)	$(26)	$(141)	$(13)	$(180)
Net assets (liabilities)(3)	$475	$920	$(1)	$1,394	$335	$991	$14	$1,340

(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 $1 million and $44 million as of June 30, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended June 30, 2015 and December 31, 2014:

	Derivative Asset	Derivative Liability	Net Asset (Liability)
	(In millions)		
January 1, 2014 Balance	$3	$(11)	$(8)
Unrealized gain (loss)	34	(1)	33
Purchases	15	(16)	(1)
Settlements	(25)	15	(10)
December 31, 2014 Balance	$27	$(13)	$14
Unrealized gain	4	3	7
Purchases	9	(10)	(1)
Settlements	(30)	9	(21)
June 30, 2015 Balance	$10	$(11)	$(1)

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended June 30, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(1)	Model	RTO auction clearing prices	($5.10) to $9.20	$1.00	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, AFS securities and notes receivables.

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 first 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 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, nuclear fuel disposal and NUG 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, nuclear fuel disposal and NUG trusts as of June 30, 2015 and December 31, 2014:

	June 30, 2015[1]			December 31, 2014[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,808	$25	$1,833	$1,724	$27	$1,751
FES	824	13	837	788	13	801
Equity securities						
FirstEnergy	$664	$33	$697	$533	$58	$591
FES	462	19	481	329	31	360

(1) Excludes short-term cash investments: FE Consolidated - $58 million; FES - $47 million.
(2) Excludes short-term cash investments: FE Consolidated - $241 million; FES - $204 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three and six months ended June 30, 2015 and 2014 were as follows:

Three Months Ended

June 30, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$448	$42	$(39)	$(17)	$25
FES	187	32	(27)	(16)	15

June 30, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$543	$35	$(15)	$(1)	$24
FES	284	30	(12)	(1)	14

Six Months Ended

June 30, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$819	$102	$(89)	$(24)	$50
FES	376	70	(55)	(22)	29

June 30, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,164	$63	$(31)	$(3)	$49
FES	707	49	(17)	(3)	29

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of June 30, 2015 and December 31, 2014:

	June 30, 2015			December 31, 2014		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$10	$2	$12	$13	$4	$17

The held-to-maturity debt securities contractually mature by June 30, 2017. Investments in employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $636 million as of June 30, 2015 and $626 million as of December 31, 2014, 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 and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	June 30, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$19,728	$21,195	$19,828	$21,733
FES	3,028	3,146	3,097	3,241

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of June 30, 2015 and December 31, 2014.

8. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating 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 net income 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 $10 million and $8 million as of June 30, 2015 and December 31, 2014, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $2 million of net unamortized losses is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $46 million and $50 million as of June 30, 2015 and December 31, 2014, respectively. Based on current estimates, approximately $9 million of these unamortized losses is expected to be amortized to interest expense during the next twelve months.

Refer to Note 4, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the three and six months ended June 30, 2015 and 2014.

As of June 30, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as cash flow hedges.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. As of June 30, 2015 and December 31, 2014, 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 $26 million and $32 million as of June 30, 2015 and December 31, 2014, respectively. During the next twelve months, approximately $12 million of the unamortized gains is expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $3 million during the three months ended June 30, 2015 and 2014 and $6 million during the six months ended June 30, 2015 and 2014.

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. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy’s coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs.

As of June 30, 2015, FirstEnergy’s net asset position under commodity derivative contracts was $31 million, which related to FES positions. Under these commodity derivative contracts, FES posted $60 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $6 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of June 30, 2015, an adverse change of 10% in commodity prices would increase net income by approximately $25 million during the next twelve months.

NUGs

As of June 30, 2015, FirstEnergy's net liability position under NUG contracts was $140 million, representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of June 30, 2015, FirstEnergy's and FES' FTR position was a $10 million net asset and a $1 million net liability, respectively, and FES posted $6 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 and through the direct allocation of FTRs from PJM. PJM has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

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	Fair Value		Derivative Liabilities	Fair Value	
	June 30, 2015	December 31, 2014		June 30, 2015	December 31, 2014
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$149	$121	Commodity Contracts	$(148)	$(154)
FTRs	22	38	FTRs	(12)	(13)
	171	159		(160)	(167)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs(1)	(141)	(153)
Commodity Contracts	103	51	Noncurrent Liabilities - Other		
FTRs	1	1	Commodity Contracts	(73)	(13)
NUGs(1)	1	2	FTRs	(1)	(1)
	105	54		(215)	(167)
Derivative Assets	$276	$213	Derivative Liabilities	$(375)	$(334)

(1) NUG contracts are subject to regulatory accounting treatment. Changes in fair value do not impact earnings.

FirstEnergy enters into contracts with counterparties that allow for net settlement of derivative assets and derivative liabilities. 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 instruments 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		
June 30, 2015	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$252	$(202)	$—	$50
FTRs	23	(13)	—	10
NUG contracts	1	—	—	1
	$276	$(215)	$—	$61
Derivative Liabilities				

Commodity contracts	$(221)	$202	$11	$(8)
FTRs	(13)	13	—	—
NUG contracts	(141)	—	—	(141)
	$(375)	$215	$11	$(149)

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December 31, 2014	Fair Value	Amounts Not Offset in Consolidated Balance Sheet		
		Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$172	$(126)	$—	$46
FTRs	39	(14)	—	25
NUG contracts	2	—	—	2
	$213	$(140)	$—	$73
Derivative Liabilities				
Commodity contracts	$(167)	$126	$35	$(6)
FTRs	(14)	14	—	—
NUG contracts	(153)	—	—	(153)
	$(334)	$140	$35	$(159)

The following table summarizes the volumes associated with FirstEnergy’s outstanding derivative transactions as of June 30, 2015:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	23	54	(31)	MWH
FTRs	54	—	54	MWH
NUGs	5	—	5	MWH
Natural Gas	39	1	38	mmBTU

The effect of active derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income during the three and six months ended June 30, 2015 and 2014, are summarized in the following tables:

	Three Months Ended June 30,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2015				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense [1]	$11	$(2)	$—	$9
Realized Gain (Loss) Reclassified to:				
Revenues [2]	$8	$8	$—	$16
Purchased Power Expense [3]	(25)	—	—	(25)
Other Operating Expense [4]	—	(13)	—	(13)
Fuel Expense	(5)	—	—	(5)

(1) Includes $11 million for commodity contracts and ($2) million for FTRs associated with FES.
(2) Includes $8 million for commodity contacts and $8 million for FTRs associated with FES.
(3) Includes ($25) million for commodity contracts associated with FES.
(4) Includes ($13) million for FTRs associated with FES.

	Three Months Ended June 30,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense [5]	$(70)	$13	$—	$(57)
Realized Gain (Loss) Reclassified to:				
Revenues [6]	$2	$(1)	$—	$1
Purchased Power Expense [7]	22	—	—	22
Other Operating Expense [8]	—	(10)	—	(10)
Fuel Expense	2	—	—	2
Interest Expense	—	—	6	6

(5) Includes ($70) million for commodity contracts and $13 million for FTRs associated with FES.
(6) Represents losses on structured financial contracts. Includes $2 million for commodity contracts and ($1) million for FTRs associated with FES.
(7) Realized losses on financially settled wholesale sales contracts of $16 million resulting from higher market prices were netted in purchased power. Includes $22 million for commodity contracts associated with FES.
(8) Includes ($9) million for FTRs associated with FES.

	Six Months Ended June 30,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2015				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[1]	$22	$(15)	$—	$7
Realized Gain (Loss) Reclassified to:				
Revenues[2]	$7	$45	$—	$52
Purchased Power Expense[3]	(28)	—	—	(28)
Other Operating Expense[4]	—	(26)	—	(26)
Fuel Expense	(21)	—	—	(21)

(1) Includes $22 million for commodity contracts and ($14) million for FTRs associated with FES.
(2) Includes $7 million for commodity contracts and $44 million for FTRs associated with FES.
(3) Includes ($28) million for commodity contracts associated with FES.
(4) Includes ($26) million for FTRs associated with FES.

	Six Months Ended June 30,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[5]	$(58)	$18	$—	$(40)
Realized Gain (Loss) Reclassified to:				
Revenues[6]	$(11)	$51	$—	$40
Purchased Power Expense[7]	458	—	—	458
Other Operating Expense[8]	—	(17)	—	(17)
Fuel Expense	11	—	—	11
Interest Expense	—	—	6	6

(5) Includes ($58) million for commodity contracts and $18 million for FTRs associated with FES.
(6) Represents losses on structured financial contracts. Includes ($11) million for commodity contracts and $50 million for FTRs associated with FES.
(7) Realized losses on financially settled wholesale sales contracts of $337 million resulting from higher market prices were netted in purchased power. Includes $458 million for commodity contracts associated with FES
(8) Includes ($16) million for FTRs associated with FES.

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during the three and six months ended June 30, 2015 and 2014. Changes in the value of these instruments are deferred for future recovery from (or credit to) customers:

	Three Months Ended June 30,		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of April 1, 2015	$(148)	$1	$(147)
Unrealized loss	(8)	—	(8)
Purchases	—	12	12
Settlements	16	(1)	15
Outstanding net asset (liability) as of June 30, 2015	$(140)	$12	$(128)
Outstanding net asset (liability) as of April 1, 2014	$(185)	$3	$(182)
Unrealized loss	(2)	—	(2)
Purchases	—	11	11
Settlements	18	(4)	14
Outstanding net asset (liability) as of June 30, 2014	$(169)	$10	$(159)

	Six Months Ended June 30,		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2015	$(151)	$11	$(140)
Unrealized gain (loss)	(16)	1	(15)
Purchases	—	12	12
Settlements	27	(12)	15
Outstanding net asset (liability) as of June 30, 2015	$(140)	$12	$(128)
Outstanding net liability as of January 1, 2014	$(202)	$—	$(202)
Unrealized gain	25	4	29
Purchases	—	11	11
Settlements	8	(5)	3
Outstanding net asset (liability) as of June 30, 2014	$(169)	$10	$(159)

9. 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 by 10% and reduce electricity demand by 15%, in each case by 2015, 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. The projected costs of the 2015-2017 plan are approximately $64 million for that three year period, of which $9 million was incurred through June 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2016 and beyond, beginning with the goal of 0.2% for 2016 and ramping up thereafter to reach 2%. 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 (the February 27 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. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. 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 27 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 27 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. The Staff of the MDPSC also recommended 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 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 March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC has set an initial hearing on the Staff of the MDPSC's analysis and recommendations for September 1-2, 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC’s regulations. The MDPSC has scheduled a hearing on the reports filed by PE and the other electric utilities in Maryland for August 24, 2015.

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.

On March 26, 2015, the NJBPU entered final orders which together provide an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding filed in November 2012 directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed, including a study related to reliability. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such study, which will include operational and financial components and is expected to take approximately one year to complete.

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: 1) calculating savings using a 5 year look back from the beginning of the test year; 2) allocating savings with 75% retained by the company and 25% allocated to rate payers; and 3) 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 has filed to participate as a respondent in that proceeding, which remains pending.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies primarily operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The matter has not yet been scheduled for oral argument.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled Powering Ohio's Progress. The Ohio Companies initially requested a decision by the PUCO by April 8, 2015. The Ohio Companies filed a partial Stipulation and Recommendation on December 22, 2014, a Supplemental Stipulation and Recommendation on May 28, 2015, and a Second Supplemental Stipulation and Recommendation on June 4, 2015. The evidentiary hearing on the ESP IV is now scheduled to commence on August 31, 2015.

The material terms of the proposed plan as filed include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continuing collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Providing economic development and assistance to low-income customers for the three-year plan period;
- An Economic Stability Program providing for a retail rate stability rider to flow through charges or credits representing the net result of the costs paid to FES through a proposed 15-year purchase power agreement for the output of Sammis, Davis-Besse and FES' share of OVEC against the revenues received from selling the output into the PJM markets over the same period;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year that allows continued investment supporting the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including appropriately such costs from MISO along with

such costs from PJM, subject to the outcome of certain FERC proceedings; and

- General updates to electric service regulations and tariffs to reflect regulatory orders, administrative rule changes, and current practices.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to the outcome of a legislative study committee. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to the outcome of a legislative study committee.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

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, subject to the outcome of a legislative study committee, 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 part of the purchases arising from one auction and directing 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. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013. 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. The matter remains pending.

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.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over 29-months concluding in the second quarter of 2013. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. The United States District Court for the Eastern District of Pennsylvania granted the PPUC's motion to dismiss the complaint filed by ME and PN to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. As a result of the U.S. District Court's decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013. On appeal, in a split decision, two judges of a three-judge panel of the Third Circuit affirmed the U.S. District Court's dismissal of the complaint, agreeing that ME and PN had litigated the issue in the state proceedings and thus were precluded from subsequent litigation in federal court. ME and PN timely filed for rehearing and rehearing en banc; the Third Circuit rejected that rehearing request. ME and PN filed a Petition for Certiorari with the United States Supreme Court on February 12, 2015, and that Court denied the Petition on May 26, 2015.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008), the PPUC was charged with reviewing the cost effectiveness of all Pennsylvania EDC's energy efficiency and peak demand reduction programs. In 2012, the PPUC found the energy efficiency programs to be cost effective and directed all of the EDCs in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. At that time, the PPUC deferred ruling on the need to create peak demand reduction targets and did not include a peak demand reduction requirement in the Phase II plans. On March 14, 2013, the PPUC adopted a settlement among the Pennsylvania Companies and interested parties and approved the Pennsylvania Companies' Phase II EE&C Plans. Total costs of these plans are expected to be approximately $234 million and 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. EDCs are permitted to recover costs for implementing Phase III EE&C plans.

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings requested approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. On February 3, 2015, each of the Pennsylvania Companies filed a Joint Petition for Settlement seeking PPUC approval of the agreements reached in each proceeding which, among other things, provided for an increase in annual revenues of $292.8 million ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP). The sole issue reserved for briefing was with respect to the scope and pricing of the Companies' proposed LED offerings. Recommended Decisions were issued by the ALJs recommending approval of the settlements and implementation of the Pennsylvania Companies' LED lighting offerings as proposed in their original filings. On April 9, 2015, the PPUC adopted the ALJs' Recommended Decisions and approved the settlements. The settlements will result in $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 revised implementation plans regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. On May 19, 2015, the PPUC granted a forty-five day extension for the filing of revised implementation plans with respect to certain of the matters raised in its March 30, 2015 Order. On May 29, 2015 and July 13, 2015, the Pennsylvania Companies filed their revised implementation plan. The cost of compliance is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provides for: a $15 million increase in base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a 5-year period approximately $46 million of storm restoration costs; and elimination of the Temporary Transaction Surcharge for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates. MP and PE's current ENEC rates went into effect on February 25, 2015, in accordance with a settlement approved by the WVPSC on January 29, 2015.

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

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new 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 most recently 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. Settlement discussions under a FERC-appointed settlement judge are ongoing.

The PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between the PJM Region and: (1) the NYISO region; (2) the MISO region; and (3) the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the costs of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region, or, in the case of MISO, indicate that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. As of May 14, 2015, FERC has accepted the PJM/NYISO, PJM/MISO and PJM/SERTP filings, subject to further compliance requirements. FERC’s acceptance of the PJM/SERTP filing is also subject to refund and the SERTP region participants’ related Order No. 1000 interregional compliance proceedings.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent “right of first refusal” to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM’s RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No.1000 compliance filing.

The outcome of the remaining pending proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

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 move. 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. FirstEnergy's request for rehearing of FERC's order remains pending.

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. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. On April 22, 2015, certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC’s prior ruling rejecting MISO’s proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. Reply comments were filed June 22, 2015. The matter is now before FERC for consideration.

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 those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an “historical looking” approach, where transmission rates reflect actual costs for the prior year, to a “forward looking” approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. Several parties protested ATSI's filing. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings. FERC also initiated an inquiry pursuant to Section 206 of the FPA into ATSI's ROE and certain other matters, with a refund effective date of January 12, 2015, for any refund resulting from the inquiry. On July 20, 2015, ATSI and certain parties filed a settlement agreement with FERC, which remains subject to FERC approval. The agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: i) 12.38% for the period commencing January 1, 2015 through June 30, 2015; ii) 11.06% for the period commencing July 1, 2015 through December 31, 2015; iii) 10.38% for the period commencing January 1, 2016. The 10.38% ROE value shall remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2018. The agreement currently is pending at FERC and ATSI anticipates that it will be approved later this year.

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. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable: of (i) a lease of real property and rights associated with the utilities' transmission assets to MAIT; (ii) a Mutual Assistance Agreement; (iii) that MAIT be deemed a public utility; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) approval of certain affiliated interest agreements. If approved, JCPL, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. FERC approval is expected within six months with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective asset contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011. The California Parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit issued a decision remanding the case to FERC for further proceedings.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

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 (an equity method investment for FE), 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 hearing if the parties do 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. The hearing concluded on April 22, 2015, and post-hearing briefing is ongoing.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC’s ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the “zone of reasonableness” that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England Inc. transmission owners. On March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggested that FERC address the remaining concerns in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. In January 2015, the RTOs and affected parties indicated to FERC that discussions on the various issues are continuing. At FERC's direction, on May 12 and 13, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam, including capacity portability, to assist the FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 and Lakeshore Unit 18 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer of Eastlake Units 1-3 was completed on April 30, 2015 and ATSI completed the conversion of Eastlake Unit 3 to a synchronous condenser in June 2015. ATSI expects to complete the conversion for Units 1 and 2 by mid 2016.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. FES and AE Supply continue to evaluate proposals to address issues with FTR allocation and funding.

On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the new complaint and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

A recent and related issue is the effect that certain financial trades have on congestion. On August 29, 2014, FERC instituted an investigation to address the question of whether the current rules regarding "Up-to Congestion" transactions are just and reasonable. FESC, on behalf of FES and the Utilities, filed comments supporting the investigation, arguing that PJM Tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase. FERC convened a technical conference on January 7, 2015 to discuss application of certain FTR-related rules to Up-to Congestion and virtual transactions and whether PJM's current uplift allocation for Up-to Congestion and virtual transactions is just and reasonable. FERC action following the technical conference is pending.

PJM Market Reform: 2014 PJM RPM Tariff Amendments

In late 2013 and early 2014, PJM submitted a series of amendments to the PJM Tariff to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. PJM's filings can be grouped into four categories: (i) DR; (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. In each of the relevant dockets, FirstEnergy and other parties submitted comments largely supporting PJM's proposed amendments. FERC largely approved the PJM Tariff amendments as proposed by PJM regarding DR, imports, and transmission upgrade modeling. Compliance filings pursuant to and requests for rehearing of certain of these orders are pending before FERC. However, FERC rejected the arbitrage/capacity replacement amendments, directing instead that a technical conference be convened to further examine the issues. The technical conference has yet to be scheduled, but the issue of arbitrage has been raised in other ongoing FERC proceedings.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed “Capacity Performance” reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance and energy market reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC’s order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.
Following FERC's issuance of the June 9, 2015 order on the Capacity Performance proposal, PJM announced that it will conduct the 2015 BRA for the 2018/2019 delivery year on August 10-14, 2015. In response to a subsequent complaint, on July 22, 2015, FERC issued an order directing PJM to permit DR and energy efficiency resources to participate in the Capacity Performance transition auctions. As a result of FERC’s order, PJM will conduct the Capacity Performance transition auction for the 2016/2017 delivery year on August 26-27, 2015, with the results to be announced on August 31, 2015. In addition, PJM will conduct the Capacity Performance transition auction for the 2017/2018 delivery year on September 3-4, 2015 with the results to be announced on September 9, 2015.
FirstEnergy and other PJM market entities also are addressing PJM’s capacity market concerns in other FERC proceedings. On November 20, 2014, FERC issued an order directing each ISO/RTO to file a report with FERC outlining each region’s efforts to ensure fuel security. PJM filed its report on February 18, 2015, advising FERC that PJM’s Capacity Performance proposal will address fuel assurance issues. On March 20, 2015, FESC, on behalf of its affected affiliates and as part of a coalition, filed responsive comments demonstrating that significant improvements were needed for PJM’s Capacity Performance proposal to address fuel assurance issues. The comments are before FERC for review.

PJM Market Reform: PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM Tariff describes the rules for calculating the “offer cap” for each unit that offers into the RPM auctions. FES disagreed with the PJM Market Monitor's approach for calculating the offer caps and in 2014, FES asked FERC to determine which PJM Tariff interpretation, FES' or the PJM Market Monitor's, was correct. On August 25, 2014, FERC issued a declaratory order agreeing with the FES interpretation of the PJM Tariff language. FERC went on, however, to initiate a new proceeding to examine whether the existing PJM Tariff language is just and reasonable. PJM filed its brief explaining why the existing PJM Tariff language is just and reasonable. Other parties, including FES, submitted responsive briefs. The briefs and related pleadings are pending before FERC.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On May 4, 2015, the United States Supreme Court granted petitions for certiorari requesting review of the May 23, 2014 opinion, and the proceeding is in the briefing phase. The U.S. Court of Appeals for the D.C. Circuit is withholding issuance of its mandate pending the United States Supreme Court's review on the merits.

On May 23, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful in light of the May 23, 2014 U.S. Court of Appeals for the D.C. Circuit decision discussed above. FESC, on behalf of FES, subsequently filed an amended complaint renewing its request that DR be removed from the May 2014 BRA. Specifically, FESC requested that FERC direct PJM to recalculate the results of the May 2014 BRA by: (i) removing DR from the PJM capacity supply pool; (ii) leaving the offers of actual capacity suppliers unchanged; and then (iii) determining which capacity suppliers clear the auction on the basis of the offers they submitted consistent with the existing PJM Tariff once the unlawful DR resources have been removed. The complaint remains pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

PJM Market Reform: PJM 2014 Triennial RPM Review

The PJM Tariff obligates PJM to perform a thorough review of its RPM program every three years. On September 25, 2014, PJM filed proposed changes to the PJM Tariff as part of the latest review cycle. Among other adjustments, the filing included: (i) shifting the VRR curve one percentage point to the right, which would increase the amount of capacity supply that is procured in the RPM auctions and the clearing price; and (ii) a change to the index used for calculating the generation plant construction costs of the Net CONE formula for the future years between triennial reviews. On November 28, 2014, FERC accepted the PJM Tariff amendments as proposed, subject to a minor compliance requirement. PJM subsequently submitted the required compliance filing. On December 23, 2014, a coalition including FESC, on behalf of its affected affiliates, requested rehearing of FERC's order. PJM's compliance filing, and the coalition's and others' requests for rehearing, remain pending before FERC.

10. COMMITMENTS, GUARANTEES AND CONTINGENCIES

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of June 30, 2015, FirstEnergy's outstanding guarantees and other assurances aggregated approximately $3.9 billion, consisting of parental guarantees ($599 million), subsidiaries' guarantees ($2.2 billion), other guarantees ($300 million) and other assurances ($717 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 exposures as of June 30, 2015, FES has posted collateral, including LOC, of $214 million. The Regulated Distribution segment has posted collateral of $1 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.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of June 30, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$410	$6	$50	$466
BB+/Ba1 Credit Ratings	$447	$6	$50	$503
Full impact of credit contingent contractual obligations	$492	$16	$50	$558

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of June 30, 2015, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $13 million with affiliated parties.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. The facility, which was originally entered into in October 2012 with a $350 million borrowing that was subsequently paid down to the current $300 million, was amended and extended in the first quarter of 2015 as further discussed below. 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.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 6, Variable Interest Entities, for additional information regarding FEV's investment in Global Holding.

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. Depending on how the EPA and the states implement the CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

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. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a D.C. Circuit decision that upheld MATS, rejecting EPA’s regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the D.C. Circuit for further proceedings. Subject to the outcome of further proceedings before the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $370 million (CES segment of $178 million and Regulated Distribution segment of $192 million), of which $167 million has been spent through June 30, 2015 ($62 million at CES and $105 million at Regulated Distribution).

Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

FirstEnergy and FES have various long-term coal supply and transportation agreements, some of which run through 2025 and certain of which are related to deactivated coal-fired plants. FirstEnergy and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties for the agreements associated with the deactivated plants and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses, do not excuse or otherwise mitigate the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FirstEnergy and FES are unable to estimate the loss or range of loss. As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going 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, and March 27, 2013, 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 possible loss or range of loss.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the United States District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG has entered into a confidential settlement to resolve these claims for an immaterial amount.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (1) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President’s Climate Action Plan goals both in terms of timing and reduction levels.

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. EPA proposed a new source performance standard in September 2013, which would not apply to any existing, modified, or reconstructed fossil fuel fired generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. EPA proposed regulations in June 2014, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by June 30, 2016, to meet EPA’s state specific CO_2 emission rate goals. EPA’s proposal allows states to request a 1-year extension for SIPs (June 30, 2017) or a 2-year extension for multi-state SIPs (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel fired electric generating units. 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 EPA to install GHG control technologies. On June 9, 2015, the U.S. Court of Appeals for the D.C. Circuit denied challenges to prevent EPA from regulating CO_2 emissions from existing fossil fuel fired electric generating units because EPA's proposed Clean Power Plant is not final agency action and therefore not ripe for review. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

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. In advance of the December 2015 United Nations Framework Convention on Climate Change meetings in Paris, 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. 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 significant 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 costs of compliance with these standards may require material capital expenditures.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a United States District Court and the treatment obligations are proposed to phase-in as permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule and any final action taken by the states, the future costs of compliance with these standards may require material capital expenditures.

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 possible 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. Depending on how the final rules are ultimately implemented, the future costs of compliance with such CCR regulations may require material capital expenditures.

The PA DEP filed a 2012 complaint against FG in the United States District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCR Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified consent decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE 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 Bruce Mansfield plant is pursuing several options for its CCRs following December 31, 2016. A June 28, 2013 complaint filed by Citizens Coal Counsel and other NGOs in the United States District Court for the Western District of Pennsylvania, against the owner and operator of a reclamation mine in LaBelle, Pennsylvania that is one possible alternative, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site. To date, no complaint has been filed. On May 22, 2015, PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility, another potential alternative for Bruce Mansfield plant CCR disposal. On July 6, 2015, Sierra Club filed a Notice of Appeal with the Pennsylvania Environmental Hearing Board challenging the renewal and reissuance of the permit for the Hatfield’s Ferry CCB disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of June 30, 2015 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 $134 million have been accrued through June 30, 2015. Included in the total are accrued liabilities of approximately $93 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 possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of June 30, 2015, FirstEnergy had approximately $2.3 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 guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted an opportunity for a hearing on the Davis-Besse license renewal application to a group of Intervenors, subject to the admissibility of contentions. On March 10, 2015, the ASLB issued an Order that terminated its jurisdiction and closed the record in the Davis-Besse license renewal proceeding. On June 9, 2015, the NRC Commissioners denied an intervenor's filed requests to reopen the record and admit a contention on the NRC’s Continued Storage Rule.

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.

The NRC continues to evaluate FENOC's analysis of 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. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal for failure to supply coal required by a long term CSA. A jury trial, appeal and other proceedings followed. On April 6, 2015, and in lieu of further appeals and litigation process, the parties agreed to a full and final settlement of all remaining claims and on April 7, 2015, ICG paid the $15 million settlement amount in full of which $12 million was allocated to AE Supply and $3 million to MP. The trial and appellate courts were notified of the settlement and the cases were discontinued by the parties.

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 9, 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.

11. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for a 93.83% 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 three and six months ended June 30, 2015 and 2014, Condensed Consolidating Balance Sheets as of June 30, 2015 and December 31, 2014, and Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2015 and 2014, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES 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 FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES’ 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)
(Unaudited)

For the Three Months Ended June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$1,074	$346	$456	$(757)	$1,119
OPERATING EXPENSES:					
Fuel	—	150	41	—	191
Purchased power from affiliates	768	—	66	(757)	77
Purchased power from non-affiliates	392	—	—	—	392
Other operating expenses	102	75	164	12	353
Provision for depreciation	2	32	47	—	81
General taxes	11	7	7	—	25
Total operating expenses	1,275	264	325	(745)	1,119
OPERATING INCOME (LOSS)	(201)	82	131	(12)	—
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	119	5	3	(126)	1
Miscellaneous income	1	3	—	—	4
Interest expense — affiliates	(7)	(2)	(1)	8	(2)
Interest expense — other	(13)	(26)	(12)	14	(37)
Capitalized interest	—	2	7	—	9
Total other income (expense)	100	(18)	(3)	(104)	(25)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(101)	64	128	(116)	(25)
INCOME TAXES (BENEFITS)	(80)	28	47	1	(4)
NET INCOME (LOSS)	$(21)	$36	$81	$(117)	$(21)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(21)	$36	$81	$(117)	$(21)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(4)	(4)	—	4	(4)
Amortized gain on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available-for-sale securities	(12)	—	(12)	12	(12)

Other comprehensive loss	(17)	(4)	(12)	16	(17)
Income tax benefits on other comprehensive loss	(6)	(2)	(4)	6	(6)
Other comprehensive loss, net of tax	(11)	(2)	(8)	10	(11)
COMPREHENSIVE INCOME (LOSS)	$(32)	$34	$73	$(107)	$(32)

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

For the Six Months Ended June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$2,406	$839	$963	$(1,712)	$2,496
OPERATING EXPENSES:					
Fuel	—	330	91	—	421
Purchased power from affiliates	1,725	—	134	(1,712)	147
Purchased power from non-affiliates	935	—	—	—	935
Other operating expenses	282	142	318	24	766
Provision for depreciation	5	62	95	(1)	161
General taxes	26	15	13	—	54
Total operating expenses	2,973	549	651	(1,689)	2,484
OPERATING INCOME (LOSS)	(567)	290	312	(23)	12
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	—	—	—	—	—
Investment income, including net income from equity investees	360	8	17	(371)	14
Miscellaneous income	1	3	—	—	4
Interest expense — affiliates	(13)	(4)	(2)	15	(4)
Interest expense — other	(26)	(52)	(25)	29	(74)
Capitalized interest	—	3	15	—	18
Total other income (expense)	322	(42)	5	(327)	(42)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(245)	248	317	(350)	(30)
INCOME TAXES (BENEFITS)	(221)	95	117	3	(6)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(24)	153	200	(353)	(24)
Discontinued operations (Note 13)	—	—	—	—	—
NET INCOME (LOSS)	$(24)	$153	$200	$(353)	$(24)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(24)	$153	$200	$(353)	$(24)

OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(8)	(8)	—	8	(8)
Amortized gain on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available-for-sale securities	(9)	—	(9)	9	(9)
Other comprehensive loss	(19)	(8)	(9)	17	(19)
Income tax benefits on other comprehensive loss	(7)	(3)	(3)	6	(7)
Other comprehensive loss, net of tax	(12)	(5)	(6)	11	(12)
COMPREHENSIVE INCOME (LOSS)	$(36)	$148	$194	$(342)	$(36)

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

For the Three Months Ended June 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$1,412	$505	$437	$(902)	$1,452
OPERATING EXPENSES:					
Fuel	—	288	46	—	334
Purchased power from affiliates	902	—	75	(902)	75
Purchased power from non-affiliates	618	—	—	—	618
Other operating expenses	242	79	135	12	468
Provision for depreciation	2	30	48	(1)	79
General taxes	18	6	5	—	29
Total operating expenses	1,782	403	309	(891)	1,603
OPERATING INCOME (LOSS)	(370)	102	128	(11)	(151)
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	2	2	23	(3)	24
Miscellaneous income	159	3	—	(158)	4
Interest expense — affiliates	(2)	(2)	(1)	3	(2)
Interest expense — other	(14)	(25)	(13)	15	(37)
Capitalized interest	—	—	8	—	8
Total other income (expense)	145	(22)	17	(143)	(3)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(225)	80	145	(154)	(154)
INCOME TAXES (BENEFITS)	(137)	23	45	2	(67)
NET INCOME (LOSS)	$(88)	$57	$100	$(156)	$(87)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(88)	$57	$100	$(156)	$(87)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(5)	(5)	—	5	(5)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available for sale securities	25	—	25	(25)	25

Other comprehensive income (loss)	17	(5)	25	(20)	17
Income taxes (benefits) on other comprehensive income (loss)	7	(1)	9	(8)	7
Other comprehensive income (loss), net of tax	10	(4)	16	(12)	10
COMPREHENSIVE INCOME (LOSS)	$(78)	$53	$116	$(168)	$(77)

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

For the Six Months Ended June 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$3,209	$820	$799	$(1,547)	$3,281
OPERATING EXPENSES:					
Fuel	—	560	93	—	653
Purchased power from affiliates	1,547	—	139	(1,547)	139
Purchased power from non-affiliates	1,643	4	—	—	1,647
Other operating expenses	470	141	285	24	920
Provision for depreciation	4	59	91	(1)	153
General taxes	39	17	12	—	68
Total operating expenses	3,703	781	620	(1,524)	3,580
OPERATING INCOME (LOSS)	(494)	39	179	(23)	(299)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(3)	(1)	(1)	—	(5)
Investment income, including net income from equity investees	3	3	44	(6)	44
Miscellaneous income	262	3	—	(261)	4
Interest expense — affiliates	(5)	(3)	(2)	6	(4)
Interest expense — other	(28)	(49)	(26)	30	(73)
Capitalized interest	—	1	19	—	20
Total other income (expense)	229	(46)	34	(231)	(14)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(265)	(7)	213	(254)	(313)
INCOME TAXES (BENEFITS)	(189)	(8)	71	3	(123)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(76)	1	142	(257)	(190)
Discontinued operations (net of income taxes of $70) Note (13)	—	116	—	—	116
NET INCOME (LOSS)	$(76)	$117	$142	$(257)	$(74)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					

NET INCOME (LOSS)	$(76)	$117	$142	$(257)	$(74)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(10)	(9)	—	9	(10)
Amortized gain on derivative hedges	(5)	—	—	—	(5)
Change in unrealized gain on available-for-sale securities	44	—	44	(44)	44
Other comprehensive income (loss)	29	(9)	44	(35)	29
Income taxes (benefits) on other comprehensive income (loss)	11	(3)	16	(13)	11
Other comprehensive income (loss), net of tax	18	(6)	28	(22)	18
COMPREHENSIVE INCOME (LOSS)	$(58)	$111	$170	$(279)	$(56)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	325	—	—	—	325
Affiliated companies	340	287	301	(525)	403
Other	45	2	10	—	57
Notes receivable from affiliated companies	394	1,072	580	(2,033)	13
Materials and supplies	54	201	221	—	476
Derivatives	158	—	—	—	158
Collateral	140	—	—	—	140
Prepayments and other	80	59	—	—	139
	1,536	1,623	1,112	(2,558)	1,713
PROPERTY, PLANT AND EQUIPMENT:					
In service	90	6,351	7,919	(382)	13,978
Less — Accumulated provision for depreciation	34	2,107	3,483	(193)	5,431
	56	4,244	4,436	(189)	8,547
Construction work in progress	3	157	757	—	917
	59	4,401	5,193	(189)	9,464
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,365	—	1,365
Investment in affiliated companies	6,957	—	—	(6,957)	—
Other	—	10	—	—	10
	6,957	10	1,365	(6,957)	1,375
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	322	—	—	(322)	—
Customer intangibles	70	—	—	—	70
Goodwill	23	—	—	—	23
Property taxes	—	7	12	—	19
Unamortized sale and leaseback costs	—	—	—	266	266
Derivatives	104	—	—	—	104
Other	51	321	11	(266)	117
	570	328	23	(322)	599
	$9,122	$6,362	$7,693	$(10,026)	$13,151
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$167	$541	$(25)	$683
Short-term borrowings-					
Affiliated companies	1,649	384	—	(2,033)	—
Other	250	8	—	—	258
Accounts payable-					

Affiliated companies	581	133	164	(581)	297
Other	24	93	—	—	117
Accrued taxes	3	41	50	(15)	79
Derivatives	155	3	—	—	158
Other	66	54	9	34	163
	2,728	883	764	(2,620)	1,755
CAPITALIZATION:					
Total equity	5,554	2,712	4,208	(6,920)	5,554
Long-term debt and other long-term obligations	695	2,199	614	(1,149)	2,359
	6,249	4,911	4,822	(8,069)	7,913
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	807	807
Accumulated deferred income taxes	7	29	696	(144)	588
Asset retirement obligations	—	191	659	—	850
Retirement benefits	36	295	—	—	331
Derivatives	69	5	—	—	74
Other	33	48	752	—	833
	145	568	2,107	663	3,483
	$9,122	$6,362	$7,693	$(10,026)	$13,151

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	415	—	—	—	415
Affiliated companies	484	487	674	(1,120)	525
Other	66	21	20	—	107
Notes receivable from affiliated companies	339	838	272	(1,449)	—
Materials and supplies	67	202	223	—	492
Derivatives	147	—	—	—	147
Collateral	229	—	—	—	229
Prepayments and other	56	41	—	(2)	95
	1,803	1,591	1,189	(2,571)	2,012
PROPERTY, PLANT AND EQUIPMENT:					
In service	133	6,217	7,628	(382)	13,596
Less — Accumulated provision for depreciation	36	2,058	3,305	(191)	5,208
	97	4,159	4,323	(191)	8,388
Construction work in progress	3	206	801	—	1,010
	100	4,365	5,124	(191)	9,398
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,365	—	1,365
Investment in affiliated companies	6,607	—	—	(6,607)	—
Other	—	10	—	—	10
	6,607	10	1,365	(6,607)	1,375
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	276	76	—	(352)	—
Customer intangibles	78	—	—	—	78
Goodwill	23	—	—	—	23
Property taxes	—	14	27	—	41
Unamortized sale and leaseback costs	—	—	—	217	217
Derivatives	52	—	—	—	52
Other	34	277	7	(204)	114
	463	367	34	(339)	525
	$8,973	$6,333	$7,712	$(9,708)	$13,310
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$18	$164	$348	$(24)	$506
Short-term borrowings-					
Affiliated companies	1,135	321	28	(1,449)	35
Other	90	9	—	—	99

Accounts payable-					
Affiliated companies	1,068	197	219	(1,068)	416
Other	46	202	—	—	248
Accrued taxes	2	62	161	(123)	102
Derivatives	166	—	—	—	166
Other	72	56	9	47	184
	2,597	1,011	765	(2,617)	1,756
CAPITALIZATION:					
Total equity	5,585	2,561	4,014	(6,575)	5,585
Long-term debt and other long-term obligations	695	2,215	859	(1,161)	2,608
	6,280	4,776	4,873	(7,736)	8,193
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	824	824
Accumulated deferred income taxes	13	—	678	(180)	511
Asset retirement obligations	—	189	652	—	841
Retirement benefits	36	288	—	—	324
Derivatives	14	—	—	—	14
Other	33	69	744	1	847
	96	546	2,074	645	3,361
	$8,973	$6,333	$7,712	$(9,708)	$13,310

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Six Months Ended June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(600)	$275	$680	$(12)	$343
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	674	62	—	(612)	124
Redemptions and Repayments-					
Long-term debt	(17)	(12)	(52)	12	(69)
Short-term borrowings, net	—	—	(28)	28	—
Other	—	(2)	—	—	(2)
Net cash provided from (used for) financing activities	657	48	(80)	(572)	53
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(2)	(95)	(167)	—	(264)
Nuclear fuel	—	—	(97)	—	(97)
Proceeds from asset sales	—	3	—	—	3
Sales of investment securities held in trusts	—	—	376	—	376
Purchases of investment securities held in trusts	—	—	(404)	—	(404)
Loans to affiliated companies, net	(55)	(234)	(308)	584	(13)
Other	—	3	—	—	3
Net cash used for investing activities	(57)	(323)	(600)	584	(396)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$—	$2	$—	$—	$2

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Six Months Ended June 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(202)	$147	$149	$(11)	$83
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	291	346	—	637
Short-term borrowings, net	—	172	—	(172)	—
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	(1)	(258)	(416)	11	(664)
Short-term borrowings, net	(74)	—	(151)	98	(127)
Other	(1)	(8)	(1)	—	(10)
Net cash provided from (used for) financing activities	424	197	(222)	(63)	336
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(4)	(74)	(399)	—	(477)
Nuclear fuel	—	—	(57)	—	(57)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	707	—	707
Purchases of investment securities held in trusts	—	—	(736)	—	(736)
Loans to affiliated companies, net	(218)	(581)	558	73	(168)
Other	—	4	—	1	5
Net cash provided from (used for) investing activities	(222)	(344)	73	74	(419)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$—	$2	$—	$—	$2

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12. SEGMENT INFORMATION

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

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

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

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are primarily from transmission services provided pursuant to the PJM Tariff to LSEs. 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. This business segment currently controls 13,169 MWs of capacity. The CES segment’s net income is 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. In 2014, the CES segment began reducing its exposure to weather-sensitive loads, maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams and modifying its hedging strategy to optimize risk management and market upside opportunities.

Corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment and interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. As of June 30, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.9 billion was borrowed by FE under its revolving credit facility. Reconciling adjustments for the elimination of inter-segment transactions are shown separately in the accompanying table.

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other	Reconciling Adjustments	Consolidated
	(In millions)					
June 30, 2015						
External revenues	$2,239	$ 269	$1,034	$(42)	$(35)	$3,465
Internal revenues	—	—	162	—	(162)	—
Total revenues	2,239	269	1,196	(42)	(197)	3,465
Depreciation	170	38	99	15	—	322
Amortization of regulatory assets, net	57	2	—	—	—	59
Investment income (loss)	12	—	(7)	2	(10)	(3)
Interest expense	146	40	48	49	(1)	282
Income taxes (benefits)	91	52	(7)	(19)	(2)	115
Net income (loss)	156	89	(12)	(46)	—	187
Total assets	28,353	7,055	16,711	886	—	53,005
Total goodwill	5,092	526	800	—	—	6,418
Property additions	312	297	191	18	—	818
June 30, 2014						
External revenues	$2,065	$ 191	$1,311	$(31)	$(40)	$3,496
Internal revenues	—	—	182	—	(182)	—
Total revenues	2,065	191	1,493	(31)	(222)	3,496
Depreciation	164	30	96	12	—	302
Amortization of regulatory assets, net	16	3	—	—	1	20
Investment income (loss)	15	—	21	2	(9)	29
Interest expense	147	30	48	30	7	262
Income taxes (benefits)	77	32	(65)	(30)	12	26
Net income (loss)	158	63	(119)	(26)	(12)	64
Total assets	27,901	5,840	17,137	510	—	51,388
Total goodwill	5,092	526	800	—	—	6,418
Property additions	340	384	240	24	—	988
Six Months Ended						
June 30, 2015						
External revenues	$4,801	$ 507	$2,209	$(84)	$(71)	$7,362
Internal revenues	—	—	422	—	(422)	—
Total revenues	4,801	507	2,631	(84)	(493)	7,362
Depreciation	342	75	195	29	—	641
Amortization of regulatory assets, net	86	5	—	—	—	91
Investment income	25	—	4	5	(20)	14
Interest expense	290	79	96	96	—	561
Income taxes (benefits)	213	94	(11)	(37)	—	259

Income (loss) from continuing operations	364	161	(21)	(95)	—	409
Discontinued operations, net of tax	—	—	—	—	—	—
Net income (loss)	364	161	(21)	(95)	—	409
Property additions	592	551	317	26	—	1,486
June 30, 2014						
External revenues	$4,615	$ 373	$2,833	$(71)	$(72)	$7,678
Internal revenues	—	—	431	—	(431)	—
Total revenues	4,615	373	3,264	(71)	(503)	7,678
Depreciation	326	60	187	23	—	596
Amortization of regulatory assets, net	(15)	6	—	—	1	(8)
Investment income	30	—	35	5	(19)	51
Interest expense	298	55	94	73	7	527
Income taxes (benefits)	202	62	(138)	(56)	4	74
Income (loss) from continuing operations	372	114	(243)	(58)	1	186
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	372	114	(157)	(58)	1	272
Property additions	609	601	558	41	—	1,809

13. DISCONTINUED OPERATIONS

On February 12, 2014, certain of FirstEnergy's subsidiaries sold eleven hydroelectric power stations to a subsidiary of LS Power 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 six months ended June 30, 2014, was included in discontinued operations in the Consolidated Statement of Income. Included in income from discontinued operations in the six months ended June 30, 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 the six months ended June 30, 2014, were included in discontinued operations in the Consolidated Statement of Income.

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

FIRSTENERGY CORP.

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

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

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

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are primarily from transmission services provided pursuant to the PJM Tariff to LSEs. 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. This business segment currently controls 13,169 MWs of capacity.

The CES segment’s net income is 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.

The segment derives its revenues from the sale of generation to direct, governmental aggregation, POLR, structured and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and DR programs, as well as regulatory and legislative actions, such as MATS, among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies. In 2014, the CES segment began reducing its exposure to weather-sensitive loads, maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams and modifying its hedging strategy to optimize risk management and market upside opportunities.

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating unit. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

FirstEnergy engages in discussions with various commodity vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

Corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment and 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. As of June 30, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.9 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

In 2014, FirstEnergy launched programs to begin reinvesting in its Regulated Transmission and Regulated Distribution segments. This investment strategy is focused on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure.

Focusing on reinvestment in its regulated operations will also provide stability and growth for FirstEnergy as this plan is implemented over the coming years. The centerpiece of FirstEnergy's regulated investment strategy is the Energizing the Future transmission expansion plan, which was introduced in late 2013. The initial phase of this plan includes $4.2 billion in investments from 2014 through 2017 to modernize the transmission system owned by FirstEnergy's Regulated Transmission segment. In 2014, Regulated Transmission's capital expenditures were $1.4 billion and the segment expects 2015 capital expenditures of $970 million for regulatory required and reliability enhancement projects. FirstEnergy expects to fund these investments through a combination of debt and cash, including from previously announced equity issuances through a stock investment plan. In the future, FirstEnergy may consider additional equity to fund capital investments in the regulated operations.

The transmission investment program is also designed to prepare the electrical system for load growth, including increased demand related to continued development in the Marcellus and Utica shale regions of the utilities' western Pennsylvania, eastern Ohio and West Virginia service areas. While FirstEnergy continues to monitor recent developments in shale related activity, in 2014, more than 400 MWs of new industrial demand associated with shale gas activity came online in FirstEnergy's region, and more than 1,000 MWs of additional planned expansion is expected at customer facilities through 2019.

FirstEnergy completed its cash flow improvement plan to identify both immediate and long-term savings opportunities. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three year period.

During the second quarter of 2015, FirstEnergy completed a number of key regulatory initiatives and continues to pursue other regulatory initiatives across its utility footprint, focused on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives include:

- Implementation of new rates for ME, PN, Penn and WP effective May 3, 2015, resulting from the PPUC's approval of rate case settlement agreements in April 2015, providing for an increase in annual revenues of approximately $293 million, and approximately $88 million of additional annual operating expenses.
- The Ohio Companies' ESP IV, Powering Ohio's Progress, filed in August 2014, with an expected decision in late 2015 or early 2016 that would freeze base distribution rates through May 2019 while helping ensure continued availability of more than 3,200 MWs, if approved by the PUCO, of FirstEnergy's critical baseload generating assets primarily located in the state and serving the long-term energy needs of Ohio customers.
- ATSI's October 2014 rate filing with FERC to request transmission rates using a "forward looking" approach, where transmission rates would be based on estimated costs for the current year with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's rate filing to become effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings and FERC's inquiry into ATSI's ROE. On July 20, 2015, ATSI and certain parties filed a settlement agreement with FERC, which remains subject to FERC's approval. The agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: i) 12.38% for the period commencing January 1, 2015 through June 30, 2015; ii) 11.06% for the period commencing July 1, 2015 through December 31, 2015; and iii) 10.38% for the the period commencing January 1, 2016. The 10.38% ROE should remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2018. The agreement currently is pending at FERC and ATSI anticipates that it will be approved later this year.
- On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. If approved, MAIT will operate similar to FET's two existing stand-alone transmission subsidiaries ATSI and TrAIL. MAIT's transmission

facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. FERC approval is expected within six months, and state approvals are anticipated by mid-2016.

Additionally, on March 26, 2015, the NJBPU issued orders on JCP&L's base rate proceeding and its generic storm proceeding resulting in a reduction of approximately $34 million in JCP&L's annual revenues, including the recovery of 2011 and 2012 storm costs as well the NJBPU's recently modified CTA policy. The new rates were effective April 1, 2015.

In 2014, FirstEnergy set a new course for CES designed to limit risk in the current difficult energy market, while positioning the business to take advantage of future market upside. In 2015, FirstEnergy is continuing to reposition its competitive business to focus on reducing exposure to weather-sensitive load in certain sales channels and pursuing high-margin sales, while also leaving a portion of its generation available to capture future market opportunities. This strategy is designed to better position CES to benefit from opportunities as markets improve while limiting risk from continued challenging market conditions. At the same time, FirstEnergy continues to advocate for reforms that can ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability.

The CES segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of June 30, 2015, committed sales for 2015 are approximately 72 million MWHs. For the six months from July to December 2015, supply from expected generation and committed purchases is approximately 119% of committed sales assuming normal weather conditions. As of June 30, 2015, committed sales for 2016 and 2017 are approximately 53 million MWHs and 31 million MWHs, respectively. On average, the CES segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs available from purchased power agreements for wind, solar and its entitlement from OVEC. The CES segment fulfills the difference between committed sales, which is based on estimated customer usage, assuming normal weather, and electricity generated, through forward contracts and options, generation produced by its peaking units and, as necessary, purchasing power on the wholesale market.

On June 9, 2015, FERC conditionally approved substantially all of PJMs proposed Capacity Performance reforms. PJM will conduct the 2015 BRA for the 2018/2019 delivery year on August 10-14, 2015, and the Capacity Performance transition auctions shortly thereafter.

FirstEnergy has also reduced the size and shifted the mix of its generating assets, while reducing operating expenses and capital expenditures, including the deactivation of certain plants and the 2014 sale of certain hydroelectric facilities. As a result, the remaining competitive fleet is more cost-effective, efficient and environmentally sound. FirstEnergy is on track to exceed benchmarks established by MATS and other environmental regulations. FirstEnergy’s total cost for MATS compliance is expected to be approximately $370 million ($178 million at CES and $192 million at Regulated Distribution), of which $167 million has been spent through June 30, 2015 ($62 million at CES and $105 million at Regulated Distribution).

Operational Matters

On May 24, 2015, the 939-MW Beaver Valley Unit 1 returned to service following a scheduled month-long shutdown for refueling and maintenance. During the outage, 61 of the 157 fuel assemblies were exchanged. Numerous safety inspections and preventative maintenance and improvement projects were completed to ensure continued safe operations. More than 1,000 temporary contractor workers and FENOC and FirstEnergy employees supplemented the Beaver Valley workforce to complete outage work.

FirstEnergy has decided to move forward with the planned water treatment upgrades at the Bruce Mansfield plant, which are necessary to allow the plant to continue to operate after December 31, 2016, when the LBR CCR impoundment is required to close. Estimated 2015 capital expenditures for the water treatment upgrades are approximately $117 million and are included in FirstEnergy's 2015 capital expenditures forecast of $2.9 billion.

Financial Overview	Three Months Ended June 30,							Six Months Ended June 30,						
(In millions, except per share amounts)	2015	2014	Change					2015	2014		Change			
REVENUES:	$3,465	$3,496	$(31	)	(1	)%		$7,362	$7,678		$(316	)	(4	)%
OPERATING EXPENSES:														
Fuel	383	550	(167	)	(30	)%		896	1,167		(271	)	(23	)%
Purchased power	989	1,083	(94	)	(9	)%		2,102	2,538		(436	)	(17	)%
Other operating expenses	916	1,021	(105	)	(10	)%		1,973	2,203		(230	)	(10	)%
Provision for depreciation	322	302	20		7	%		641	596		45		8	%
Amortization (deferral) of regulatory assets, net	59	20	39		195	%		91	(8	)	99		1,238	%
General taxes	242	228	14		6	%		511	499		12		2	%
Total operating expenses	2,911	3,204	(293	)	(9	)%		6,214	6,995		(781	)	(11	)%
OPERATING INCOME	554	292	262		90	%		1,148	683		465		68	%
OTHER INCOME (EXPENSE):														

Loss on debt redemptions	—	(1)	1	100 %	—	(8)	8	100 %
Investment income (loss)	(3)	29	(32)	(110)%	14	51	(37)	(73)%
Interest expense	(282)	(262)	(20)	(8)%	(561)	(527)	(34)	(6)%
Capitalized financing costs	33	32	1	3 %	67	61	6	10 %
Total other expense	(252)	(202)	(50)	(25)%	(480)	(423)	(57)	(13)%
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	302	90	212	236 %	668	260	408	157 %
INCOME TAXES	115	26	89	342 %	259	74	185	250 %
INCOME FROM CONTINUING OPERATIONS	187	64	123	192 %	409	186	223	120 %
Discontinued operations (net of income taxes of $69) (Note 13)	—	—	—	— %	—	86	(86)	(100)%
NET INCOME	$187	$64	$123	192 %	$409	$272	$137	50 %
EARNINGS PER SHARE OF COMMON STOCK:								
Basic - Continuing Operations	$0.44	$0.16	$0.28	175 %	$0.97	$0.45	$0.52	116 %
Basic - Discontinued Operations (Note 13)	—	—	—	— %	—	0.20	(0.20)	(100)%
Basic - Net Earnings per Basic Share	$0.44	$0.16	$0.28	175 %	$0.97	$0.65	$0.32	49 %
Diluted - Continuing Operations	$0.44	$0.15	$0.29	193 %	$0.97	$0.45	$0.52	116 %
Diluted - Discontinued Operations (Note 13)	—	—	—	— %	—	0.20	(0.20)	(100)%
Diluted - Net Earnings per Diluted Share	$0.44	$0.15	$0.29	193 %	$0.97	$0.65	$0.32	49 %

For the three months ended June 30, 2015, FirstEnergy’s net income was $187 million, or basic and diluted earnings of $0.44 per share of common stock, compared to $64 million, or $0.16 per share of common stock ($0.15 diluted) for the three months ended June 30, 2014.

As further discussed below, the increase in FirstEnergy’s second quarter net income primarily resulted from a year-over-year improvement of $107 million at CES and a $26 million increase in net income at Regulated Transmission. These increases were partially offset by higher interest expense at Corporate/other and a slight decrease in net income at the Regulated Distribution segment. CES earnings in the second quarter of 2015 benefited from higher capacity revenue associated with higher capacity prices and lower operating expenses as the segment continues to execute its revised sales strategy, while Regulated Transmission earnings benefited from ATSI’s implementation of a forward looking rate effective January 1, 2015 and an increase in cost of service and rate base recovery.

For the second quarter of 2015, FirstEnergy revenues decreased $31 million, or 1%, compared to the second quarter of 2014. The decline in revenue resulted from a $297 million decrease at CES, which was due to a decline in contract sales in line with CES’ revised sales strategy to reduce weather-sensitive load and more effectively hedge its generation. The decline in CES contract sales was partially offset by higher wholesale sales, including higher spot market energy sales and increased capacity revenue associated with higher capacity prices. Partially offsetting the decrease at CES was a $174 million increase in revenue at Regulated Distribution and a $78 million increase at Regulated Transmission. The year-over-year increase in Regulated Distribution revenue primarily resulted from a net rate increase associated with the implementation of new rates at certain operating companies as well as a year-over-year increase in retail generation and retail transmission revenues. The year-over-year increase in revenues at Regulated Transmission primarily resulted from ATSI’s transition to a forward looking rate, effective January 1, 2015, based on actual costs.

For the second quarter of 2015, operating expenses decreased $293 million, or 9%, compared to the second quarter of 2014. The decrease in operating expenses primarily resulted from a $489 million decrease at CES, mainly due to lower purchased power, transmission expenses and retail-related costs associated with lower contract sales discussed above as well as lower fuel expense associated with lower economic dispatch, unit prices and coal contract termination and settlement charges. Partially offsetting this decrease was a $164 million increase in operating expenses at Regulated Distribution, which primarily resulted from an increase in purchased power associated with higher retail generation sales and higher transmission expenses as well as increased amortization of deferred storm costs at the Pennsylvania companies, JCP&L and MP effective with the implementation of new rates discussed above. Additionally, Regulated Transmission operating expenses increased $19 million primarily related to higher property taxes and depreciation expense associated with a higher asset base.

Other expenses increased $50 million, or 25%, in the second quarter of 2015 as compared to the second quarter of 2014. The increase in other expense primarily resulted from a $28 million decline in investment income at CES and a $10 million and $11 million increase in interest expense at Regulated Transmission and Corporate/Other, respectively.

For the second quarter of 2015, FirstEnergy’s effective tax rate was 38.1%, compared with an effective tax rate of 28.9% for the three-months ended June 30, 2014. The increase in in the effective tax rate is primarily due to a reduction in state deferred tax liabilities recognized in the second quarter of 2014 that resulted from changes in state apportionment factors as well as an increase in uncertain tax benefits recorded in the second quarter of 2015.

For the six months ended June 30, 2015, FirstEnergy’s net income was $409 million, or basic and diluted earnings of $0.97 per share of common stock, compared to $272 million, or basic and diluted earnings of $0.65 per share of common stock for the six months ended June 30, 2014.

The increase in net income primarily resulted from a $136 million increase at CES and a $47 million increase at Regulated Transmission, partially offset by higher interest expense at Corporate/Other. Regulated Distribution’s net income decreased slightly for the first six months of 2015 as compared to the same period of 2014. The improvement in earnings at CES resulted from higher capacity revenue and the absence of the extreme market conditions and unplanned outages in 2014, which resulted in higher costs to serve contract sales. The improvement at Regulated Transmission primarily resulted from ATSI’s transition to a forward looking rate, effective January 1, 2015, as well as an increase in cost of service and rate base recovery at ATSI.

For the six months ended June 30, 2015, revenue decreased $316 million, or 4%, compared to the same period of 2014. The decline in revenue primarily resulted from a $633 million decrease at CES associated with a decline in contract sales volumes in line with CES’ strategy discussed above, partially offset by higher unit prices and higher capacity revenues. Partially offsetting the decrease at CES, Regulated Distribution's and Regulated Transmission’s revenue increased $186 million and $134 million, respectively. The year-over-year increase at Regulated Distribution primarily resulted from a net rate increase associated with the implementation of new rates discussed above as well as a year-over-year increase in retail transmission revenues. The year-over-year increase in revenues at Regulated Transmission primarily resulted from ATSI’s transition to a forward looking rate, effective January 1, 2015, based on actual costs.

FirstEnergy operating expenses decreased $781 million, or 11%, in the first six months of 2015 compared to the same period of 2014. The decline in operating expenses resulted from a $1,009 million decrease at CES, partially offset by a $194 million increase at Regulated Distribution and a $34 million increase at Regulated Transmission. The lower operating expenses at CES were primarily the result of lower purchased power, transmission expenses and retail-related costs associated with lower contract sales discussed above. Additionally, CES fuel expense decreased year-over-year primarily associated with lower economic dispatch, and the impact of fuel contract termination costs recognized in 2014 as well as lower nuclear unit prices. The increase in operating expenses at Regulated Distribution was mainly due to higher net regulatory asset amortization associated with the recovery of storm costs and higher purchased power costs associated with higher retail load requirements. The increase in operating expenses at Regulated Transmission primarily resulted from higher depreciation and general taxes associated with a higher asset base.

For the six months ended June 30, 2015, FirstEnergy's other expense increased $57 million, or 13%, compared to 2014. The increase in other expense primarily resulted from a $31 million decline in investment income at CES and a $24 million and $16 million increase in interest expense at Regulated Transmission and Corporate/Other, respectively.

For the six months ended June 30, 2015, FirstEnergy’s effective tax rate was 38.8%, compared with an effective tax rate of 28.5% for the six months ended June 30, 2014. The increase in the effective tax rate is primarily due to a reduction in state deferred tax liabilities recognized in the second quarter of 2014 as well as an increase in uncertain tax benefits recorded in the second quarter of 2015.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's segments. A reconciliation of segment financial results is provided in Note 12, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

Summary of Results of Operations — Second Quarter 2015 Compared with Second Quarter 2014

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

Second Quarter 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,189	$269	$980	$(43)	$3,395
Other	50	—	54	(34)	70
Internal	—	—	162	(162)	—
Total Revenues	2,239	269	1,196	(239)	3,465
Operating Expenses:					
Fuel	120	—	263	—	383
Purchased power	806	—	345	(162)	989
Other operating expenses	538	35	427	(84)	916
Provision for depreciation	170	38	99	15	322
Amortization of regulatory assets, net	57	2	—	—	59
General taxes	174	26	36	6	242
Total Operating Expenses	1,865	101	1,170	(225)	2,911
Operating Income (Loss)	374	168	26	(14)	554
Other Income (Expense):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss)	12	—	(7)	(8)	(3)
Interest expense	(146)	(40)	(48)	(48)	(282)
Capitalized financing costs	7	13	10	3	33
Total Other Expense	(127)	(27)	(45)	(53)	(252)
Income (Loss) Before Income Taxes (Benefits)	247	141	(19)	(67)	302
Income taxes (benefits)	91	52	(7)	(21)	115
Net Income (Loss)	$156	$89	$(12)	$(46)	$187

Second Quarter 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,017	$191	$1,264	$(57)	$3,415
Other	48	—	47	(14)	81
Internal	—	—	182	(182)	—
Total Revenues	2,065	191	1,493	(253)	3,496
Operating Expenses:					
Fuel	129	—	421	—	550
Purchased power	746	—	519	(182)	1,083
Other operating expenses	480	31	584	(74)	1,021
Provision for depreciation	164	30	96	12	302
Amortization of regulatory assets, net	16	3	—	1	20
General taxes	166	18	39	5	228
Total Operating Expenses	1,701	82	1,659	(238)	3,204
Operating Income (Loss)	364	109	(166)	(15)	292
Other Income (Expense):					
Loss on debt redemptions	—	—	(1)	—	(1)
Investment income	15	—	21	(7)	29
Interest expense	(147)	(30)	(48)	(37)	(262)
Capitalized financing costs	3	16	10	3	32
Total Other Expense	(129)	(14)	(18)	(41)	(202)
Income (Loss) Before Income Taxes (Benefits)	235	95	(184)	(56)	90
Income taxes (benefits)	77	32	(65)	(18)	26
Net Income (Loss)	$158	$63	$(119)	$(38)	$64

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Changes Between Second Quarter 2015 and Second Quarter 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$172	$78	$(284)	$14	$(20)
Other	2	—	7	(20)	(11)
Internal	—	—	(20)	20	—
Total Revenues	174	78	(297)	14	(31)
Operating Expenses:					
Fuel	(9)	—	(158)	—	(167)
Purchased power	60	—	(174)	20	(94)
Other operating expenses	58	4	(157)	(10)	(105)
Provision for depreciation	6	8	3	3	20
Amortization of regulatory assets, net	41	(1)	—	(1)	39
General taxes	8	8	(3)	1	14
Total Operating Expenses	164	19	(489)	13	(293)
Operating Income (Loss)	10	59	192	1	262
Other Income (Expense):					
Loss on debt redemptions	—	—	1	—	1
Investment income (loss)	(3)	—	(28)	(1)	(32)
Interest expense	1	(10)	—	(11)	(20)
Capitalized financing costs	4	(3)	—	—	1
Total Other Income (Expense)	2	(13)	(27)	(12)	(50)
Income (Loss) Before Income Taxes (Benefits)	12	46	165	(11)	212
Income taxes (benefits)	14	20	58	(3)	89
Net Income (loss)	$(2)	$26	$107	$(8)	$123

Regulated Distribution — Second Quarter 2015 Compared with Second Quarter 2014

Regulated Distribution's net income decreased $2 million in the second quarter of 2015 as compared to the same period of 2014, primarily reflecting increased operating expenses and a higher effective tax rate, partially offset by a net increase in new rates implemented in 2015 at certain operating companies as well as higher distribution services revenues associated with the Ohio Companies' DCR.

Revenues —

The $174 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30, 2015	2014	Increase (Decrease)
	(In millions)		
Distribution services	$949	$854	$95
Generation sales:			
Retail	970	924	46
Wholesale	114	123	(9)
Total generation sales	1,084	1,047	37
Transmission sales:			
Retail	129	84	45
Wholesale	27	32	(5)
Total transmission sales	156	116	40
Other	50	48	2
Total Revenues	$2,239	$2,065	$174

Distribution services revenues increased $95 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and MP and PE-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 services revenues increased resulting from higher cost recovery for above market NUG costs, the Ohio Companies' DCR, and certain energy efficiency programs for the Pennsylvania Companies. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended June 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	11,839	11,918	(0.7)%
Commercial	10,411	10,292	1.2%
Industrial	12,688	12,824	(1.1)%
Other	145	147	(1.4)%
Total Electric Distribution MWH Deliveries	35,083	35,181	(0.3)%

Distribution deliveries to residential customers decreased 0.7% as a result of declining average customer usage due, in part, to increasing energy efficiency mandates, partially offset by a slight increase in deliveries resulting from cooling degree days that were 26% above 2014 and 30% above normal. Deliveries to commercial customers increased 1.2%, primarily due to weather related usage described above. Deliveries to industrial customers decreased 1.1%, as the increase from shale and petroleum customers was more than offset by a decrease from steel customers.

The following table summarizes the price and volume factors contributing to the $37 million increase in generation revenues for the second quarter of 2015 compared to the same period of 2014:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$38
Change in prices	8
	46
Wholesale:	
Effect of decrease in sales volumes	(15)
Change in prices	(13)
Capacity Revenue	19
	(9)
Increase in Generation Revenues	$37

The increase in retail generation sales volumes was primarily due to decreased customer shopping in Ohio, Pennsylvania, and New Jersey and a slight increase in weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 80% from 82% for the Ohio Companies, 67% from 69% for the Pennsylvania Companies and 52% from 54% for JCP&L.

The decrease in wholesale generation revenues of $9 million reflects decreased volume associated with the termination of a NUG contract at JCP&L in November of 2014 and lower economic dispatch associated with low spot market energy prices. Partially offsetting these decreases 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 to earnings.

The increase in retail transmission revenues of $45 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings.

Operating Expenses —

Total operating expenses increased $164 million primarily due to the following:

- Fuel expense decreased $9 million in the second quarter of 2015 as compared to the same period in 2014 primarily related to lower unit prices and lower generation associated with lower unit dispatch associated with low spot market energy prices.

- Purchased power costs were $60 million higher in the second quarter of 2015 as compared to the same period in 2014 primarily due to increased volumes reflecting decreased customer shopping as well as higher capacity expense at MP, partially offset by lower purchases resulting from the termination of a NUG contract at JCP&L.

Source of Change in Purchased Power	Increase(Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 3
Change due to increased volumes	60
	63
Purchases from affiliates:	
Change due to decreased unit costs	(6)
Change due to decreased volumes	(12)
	(18)
Capacity Expense	16
Increase in costs deferred	(1)
Increase in Purchased Power Costs	$ 60

- Other operating expenses increased $58 million primarily due to:

- Higher transmission expenses of $44 million primarily due to increases in network transmission expenses at the Ohio Companies. The difference between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings,
- Higher operating and maintenance costs of $6 million primarily associated with increased employee benefit costs,
- Increased regulated generation operating and maintenance expenses of $8 million, reflecting higher outage costs in 2015, as compared to the second quarter of 2014.

- Depreciation expense increased $6 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.

- Net amortization of regulatory assets increased $41 million primarily due to the recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above, above market NUG costs, as well as lower energy efficiency program cost deferrals reflecting a rate decrease in 2014 for the Pennsylvania Companies. This increase was partially offset by lower default generation service cost amortization compared to the second quarter of 2014 in Pennsylvania.

- General taxes increased $8 million primarily due to higher revenue related taxes in Pennsylvania as well as higher property taxes in Ohio.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.8% and 32.8% for the quarter ended June 30, 2015 and 2014, respectively. The increase in the effective tax rate primarily resulted from tax benefits recognized in the second quarter of 2014 associated with changes in state apportionment factors.

Regulated Transmission — Second Quarter 2015 Compared with Second Quarter 2014

Net income increased $26 million in the second quarter of 2015 compared to the same period of 2014. Higher transmission revenues associated with ATSI's "forward looking" rate, reflecting incremental cost of service and rate base recovery, were partially offset by higher interest costs.

Revenues —

Total revenues increased $78 million principally due to higher revenue requirements at ATSI and TrAIL, reflecting incremental cost of service and rate base recovery resulting from their annual rate filings. Effective January 1, 2015, ATSI's formula rate calculation transitioned to a "forward looking" approach, where transmission revenues are based on actual costs, subject to a provision for rate refund.

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

Revenues by Transmission Asset Owner	Three Months Ended June 30, 2015	2014	Increase
	(In millions)		
ATSI	$127	$57	$70
TrAIL	65	57	8
PATH	3	3	—
Utilities	74	74	—
Total Revenues	$269	$191	$78

Operating Expenses —

Total operating expenses increased $19 million principally due to higher property taxes and depreciation at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expense —

Total other expense increased $13 million in the second quarter of 2015 as compared to the same period of 2014 primarily due to increased interest expense resulting from debt issuances of $1.0 billion at FET and $400 million at ATSI in 2014, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Transmission's effective tax rate was 36.9% and 33.7% for the quarter ended June 30, 2015 and 2014, respectively. The increase in the effective tax rate primarily resulted from tax benefits recognized in the second quarter of 2014 associated with changes in state apportionment factors.

CES — Second Quarter 2015 Compared with Second Quarter 2014

Operating results increased $107 million in the second quarter of 2015, compared to the same period of 2014, primarily resulting from higher capacity revenues, lower operating costs, including lower termination and settlement costs related to coal contracts, and a decrease in retail-related costs, partially offset by lower contract sales. Additionally, although wholesale short-term transactions increased year-over-year, low average spot market energy prices reduced the economic dispatch of fossil generating units, limiting additional wholesale sales volumes.

Revenues —

Total revenues decreased $297 million in the second quarter of 2015, compared to the same period of 2014, primarily due to decreased sales volumes in line with CES' strategy to more effectively hedge its generation. Revenues were impacted by higher unit prices as a result of the change in sales channel mix and increased channel pricing as well as higher capacity revenues, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$324	$620	$(296)
Governmental Aggregation	218	278	(60)
Mass Market	61	100	(39)
POLR	169	197	(28)
Structured Sales	126	124	2
Total Contract Sales	898	1,319	(421)
Wholesale	216	94	122
Transmission	28	33	(5)
Other	54	47	7
Total Revenues	$1,196	$1,493	$(297)

MWH Sales by Channel	Three Months Ended June 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	6,070	11,831	(48.7)%
Governmental Aggregation	3,453	4,652	(25.8)%
Mass Market	905	1,503	(39.8)%
POLR	2,920	3,459	(15.6)%
Structured Sales	2,808	2,811	(0.1)%
Total Contract Sales	16,156	24,256	(33.4)%
Wholesale	804	21	3,728.6%
Total MWH Sales	16,960	24,277	(30.1)%

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

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(302)	$6	$—	$—	$(296)
Governmental Aggregation	(72)	12	—	—	(60)
Mass Market	(40)	1	—	—	(39)
POLR	(31)	3	—	—	(28)
Structured Sales	—	2	—	—	2
Wholesale	28	(3)	7	90	122

The Direct, Governmental Aggregation and Mass Market customer base was 1.9 million as of June 30, 2015, compared to 2.6 million as of June 30, 2014, reflecting CES' efforts to reposition its sales portfolio. Additionally, 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.

The decrease in POLR sales of $28 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions.

Wholesale revenues increased $122 million, primarily due to an increase in capacity revenue from higher capacity prices and an increase in short-term (net hourly positions) transactions, which were limited by low spot market energy prices.

Operating Expenses —

Total operating expenses decreased $489 million in the second quarter of 2015 due to the following:

- Fuel costs decreased $158 million primarily due to lower volumes associated with lower economic dispatch of fossil units resulting from low wholesale spot market energy prices and lower nuclear unit prices resulting from the suspended DOE spent nuclear fuel fee, which was effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal contracts. In the second quarter of 2015, settled litigation associated with a fuel contract resulted in a pre-tax gain of $12 million. In the second quarter of 2014, termination of a coal contract associated with deactivated plants resulted in a pre-tax loss of $67 million.
- Purchased power costs decreased $174 million due to lower volumes ($236 million) resulting from lower contract sales and lower prices ($29 million), partially offset by higher capacity expenses ($44 million) and lower net gains on financially settled contracts ($47 million). Lower volumes were primarily due to decreased load requirements resulting from CES' revised sales strategy, partially offset by decreased fossil generation discussed above. 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.

- Fossil operating costs decreased $22 million primarily due to fewer planned and unplanned outages during the three months ended June 30, 2015, as compared to the same period of 2014, partially offset by higher employee benefit expense.

- Nuclear operating costs increased $11 million primarily due to higher employee benefit expense.
- Transmission expenses decreased $55 million primarily due to decreased load requirements and lower operating reserve and market-based ancillary costs.
- Depreciation expense increased $3 million as a result of a higher asset base from projects such as MATS compliance and the Davis-Besse steam generator replacement completed in May 2014.
- General taxes decreased $3 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.
- Other operating expenses decreased $91 million primarily due to a $67 million decrease in mark-to-market expenses on commodity contract positions, and a $40 million decrease in retail-related costs, partially offset by a $16 million impairment associated with transportation equipment during the second quarter of 2015.

Other Expense —

Total other expense increased $27 million in the second quarter of 2015 as compared to the same period of 2014, primarily due to higher OTTI and lower investment income on NDT investments.

Income Tax Benefits —

CES' effective tax rate was 36.8% and 35.3% for the quarter ended June 30, 2015 and 2014, respectively. The increase in the effective tax rate primarily resulted from tax benefits recognized in the second quarter of 2014 associated with changes in state apportionment factors.

Corporate / Other — Second Quarter 2015 Compared with Second Quarter 2014

Financial results from other operating segments and reconciling items, including interest expense on holding company debt, corporate support services revenues and expenses and income taxes, resulted in an $8 million decrease in earnings in the second quarter of 2015 compared to the same period of 2014 primarily due to higher interest expense as a result of a gain recorded on interest rate swaps in the second quarter of 2014 and higher average short-term borrowings in the second quarter of 2015 as compared to the same period in 2014.

Summary of Results of Operations — First Six Months of 2015 Compared with First Six Months of 2014

Financial results for FirstEnergy's business segments in the first six months of 2015 and 2014 were as follows:

First Six Months 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,706	$ 507	$2,105	$(88)	$7,230
Other	95	—	104	(67)	132
Internal	—	—	422	(422)	—
Total Revenues	4,801	507	2,631	(577)	7,362
Operating Expenses:					
Fuel	266	—	630	—	896
Purchased power	1,781	—	743	(422)	2,102
Other operating expenses	1,135	70	946	(178)	1,973
Provision for depreciation	342	75	195	29	641
Amortization of regulatory assets, net	86	5	—	—	91
General taxes	364	50	77	20	511
Total Operating Expenses	3,974	200	2,591	(551)	6,214
Operating Income (Loss)	827	307	40	(26)	1,148
Other Income (Expense):					
Loss on debt redemptions	—	—	—	—	—
Investment income	25	—	4	(15)	14
Interest expense	(290)	(79)	(96)	(96)	(561)
Capitalized financing costs	15	27	20	5	67
Total Other Expense	(250)	(52)	(72)	(106)	(480)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	577	255	(32)	(132)	668
Income taxes (benefits)	213	94	(11)	(37)	259
Income (Loss) From Continuing Operations	364	161	(21)	(95)	409
Discontinued Operations, net of tax	—	—	—	—	—
Net Income (Loss)	$364	$ 161	$(21)	$(95)	$409

First Six Months 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,518	$ 373	$2,738	$(107)	$7,522
Other	97	—	95	(36)	156
Internal	—	—	431	(431)	—
Total Revenues	4,615	373	3,264	(574)	7,678
Operating Expenses:					
Fuel	282	—	885	—	1,167
Purchased power	1,727	—	1,242	(431)	2,538
Other operating expenses	1,107	65	1,193	(162)	2,203
Provision for depreciation	326	60	187	23	596
Amortization (deferral) of regulatory assets, net	(15)	6	—	1	(8)
General taxes	353	35	93	18	499
Total Operating Expenses	3,780	166	3,600	(551)	6,995
Operating Income (Loss)	835	207	(336)	(23)	683
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	30	—	35	(14)	51
Interest expense	(298)	(55)	(94)	(80)	(527)
Capitalized financing costs	7	24	22	8	61
Total Other Expense	(261)	(31)	(45)	(86)	(423)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	574	176	(381)	(109)	260
Income taxes (benefits)	202	62	(138)	(52)	74
Income (Loss) From Continuing Operations	372	114	(243)	(57)	186
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$372	$ 114	$(157)	$(57)	$272

Changes Between First Six Months 2015 and First Six Months 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$188	$ 134	$(633)	$ 19	$(292)
Other	(2)	—	9	(31)	(24)
Internal	—	—	(9)	9	—
Total Revenues	186	134	(633)	(3)	(316)
Operating Expenses:					
Fuel	(16)	—	(255)	—	(271)
Purchased power	54	—	(499)	9	(436)
Other operating expenses	28	5	(247)	(16)	(230)
Provision for depreciation	16	15	8	6	45
Amortization of regulatory assets, net	101	(1)	—	(1)	99
General taxes	11	15	(16)	2	12
Total Operating Expenses	194	34	(1,009)	—	(781)
Operating Income (Loss)	(8)	100	376	(3)	465
Other Income (Expense):					
Loss on debt redemptions	—	—	8	—	8
Investment income	(5)	—	(31)	(1)	(37)
Interest expense	8	(24)	(2)	(16)	(34)
Capitalized financing costs	8	3	(2)	(3)	6
Total Other Expense	11	(21)	(27)	(20)	(57)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	3	79	349	(23)	408
Income taxes (benefits)	11	32	127	15	185
Income (Loss) From Continuing Operations	(8)	47	222	(38)	223
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income (Loss)	$(8)	$ 47	$136	$ (38)	$137

Regulated Distribution — First Six Months of 2015 Compared with First Six Months of 2014

Regulated Distribution's net income decreased $8 million in the first six months of 2015 as compared to the same period of 2014, primarily reflecting increased operating expenses and a higher effective tax rate, partially offset by a net increase in new rates implemented in 2015 at certain operating companies as well as higher distribution services revenues associated with the Ohio Companies' DCR.

Revenues —

The $186 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30, 2015	2014	Increase (Decrease)
	(In millions)		
Distribution services	$1,976	$1,837	$139
Generation sales:			
Retail	2,150	2,029	121
Wholesale	259	376	(117)
Total generation sales	2,409	2,405	4
Transmission sales:			
Retail	256	179	77
Wholesale	65	97	(32)
Total transmission sales	321	276	45
Other	95	97	(2)
Total Revenues	$4,801	$4,615	$186

Distribution services revenues increased $139 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and MP and PE-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 services revenues increased resulting from higher cost recovery for above market NUG costs, the Ohio Companies' DCR, and certain energy efficiency programs for the Pennsylvania Companies, which reflected a rate decrease in 2014. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Six Months Ended June 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	28,401	28,489	(0.3)%
Commercial	21,543	21,320	1.0%
Industrial	25,428	25,524	(0.4)%
Other	292	291	0.3%
Total Electric Distribution MWH Deliveries	75,664	75,624	0.1%

Distribution deliveries to residential customers reflect lower average customer usage resulting in part from increasing energy efficiency mandates, partially offset by a slight increase in weather-related usage resulting from cooling degree days that were 26% above 2014 and 29% above normal. Deliveries to commercial customers increased 1.0% primarily due to weather related usage described above. In the first six months of 2015, heating degree days were flat to the same period of 2014 and 14% above normal. Deliveries to industrial customers decreased slightly, as the increase from shale and petroleum customers was more than offset by a decrease from steel customers.

The following table summarizes the price and volume factors contributing to the $4 million increase in generation revenues for the first six months of 2015 compared to the same period of 2014:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$113
Change in prices	8
	121
Wholesale:	
Effect of decrease in sales volumes	(93)
Change in prices	(64)
Capacity Revenue	40
	(117)
Increase in Generation Revenues	$4

The increase in retail generation sales volumes was primarily due to decreased customer shopping in Ohio, Pennsylvania, and New Jersey and a slight increase in weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 79% from 81% for the Ohio Companies, 64% from 67% for the Pennsylvania Companies and 51% from 53% for JCP&L.

Wholesale generation revenues decreased $117 million in the first six months of 2015 as compared to the same period of 2014 primarily reflecting decreased volume associated with the termination of certain NUG contracts at JCP&L and PN and lower economic dispatch 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 to earnings.

The increase in retail transmission revenues of $77 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings. The decrease in wholesale transmission revenues of $32 million primarily relates to lower congestion revenue resulting from market conditions related to extreme weather events in 2014.

Operating Expenses —

Total operating expenses increased $194 million primarily due to the following:

- Fuel expense decreased $16 million in the first six months of 2015 as compared to the same period of 2014 primarily related to lower generation associated with higher outages and lower unit dispatch resulting from low wholesale spot market energy prices.

- Purchased power costs were $54 million higher during the first six months of 2015, as compared to the same period of 2014, primarily due to increased volumes reflecting decreased customer shopping as well as higher capacity expense at MP, partially offset by lower purchases resulting from the termination of certain NUG contracts at JCP&L and PN, as well as lower default service unit prices.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$(20)
Change due to increased volumes	45
	25
Purchases from affiliates:	
Change due to decreased unit costs	(8)
Change due to volumes	—
	(8)
Capacity Expense	35
Amortization of deferred costs	2
Increase in Purchased Power Costs	$54

- Other operating expenses increased $28 million primarily due to:

- Higher operating and maintenance expense of $24 million associated with increased employee benefit costs and increased vegetation management expenses in West Virginia, which are recovered through the vegetation management surcharge effective February 25, 2015, partially offset by lower storm costs.
- Increased regulated generation operating and maintenance expenses of $5 million, reflecting higher planned outage expenses in the first six months of 2015 as compared to the same period in 2014.

- Depreciation expense increased $16 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.

- Net amortization of regulatory assets increased $101 million primarily due to the recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above as well as recovery of above market NUG costs and energy efficiency program and default generation service costs.

- General taxes increased $11 million primarily due to higher revenue related taxes in Pennsylvania as well as higher property taxes in Ohio.

Other Expense —

Other expense decreased $11 million in the first six months of 2015 primarily due to lower interest expense from short-term borrowings, as well as higher capitalized financing costs resulting from higher rates used for borrowed funds, partially offset by lower NDT investment income.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.9% and 35.2% for the first six months of 2015 and 2014, respectively. The increase in the effective tax rate primarily resulted from tax benefits recognized in the second quarter of 2014 associated with changes in state apportionment factors.

Regulated Transmission — First Six Months of 2015 Compared with First Six Months of 2014

Net income increased $47 million in the first six months of 2015 compared to the same period of 2014. Higher transmission revenues associated with ATSI's "forward looking" rate, reflecting incremental cost of service and rate base recovery, were partially offset by higher interest costs.

Revenues —

Total revenues increased $134 million principally due to higher revenue requirements at ATSI and TrAIL, reflecting incremental cost of service and rate base recovery, resulting from their annual rate filings. Effective January 1, 2015, ATSI's formula rate calculation transitioned to a "forward looking" approach, where transmission revenues are based on actual costs, subject to a provision for rate refund.

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

Revenues by Transmission Asset Owner	Six Months Ended June 30, 2015	2014	Increase
	(In millions)		
ATSI	$223	$110	$113
TrAIL	126	109	17
PATH	7	6	1
Utilities	151	148	3
Total Revenues	$507	$373	$134

Operating Expenses —

Total operating expenses increased $34 million principally due to higher property taxes and depreciation at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expense —

Other expense increased $21 million in the first six months of 2015 compared to the same period of 2014 primarily 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, partially offset by higher capitalized financing costs resulting from increased construction work in progress primarily associated with the Energizing the Future transmission expansion plan.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.9% and 35.2% for the first six months of 2015 and 2014, respectively. The increase in the effective tax rate primarily resulted from tax benefits recognized in the second quarter of 2014 associated with changes in state apportionment factors.

CES — First Six Months of 2015 Compared with First Six Months of 2014

Operating results increased $136 million in the first six months of 2015, as compared to the same period of 2014, primarily from higher capacity revenues and the absence of the extreme market conditions and unplanned outages in 2014 resulting in higher costs to serve contract sales. Subsequent to the first quarter of 2014, CES began to reduce its exposure to weather-sensitive loads and more effectively hedge its generation. As a result of that revised strategy, CES was able to successfully mitigate the extreme weather conditions that occurred in February 2015 by more effectively using its generation to supply higher customer usage as compared to the first quarter of 2014 when CES purchased power at higher prices to supply increased customer usage. Additionally, operating results were impacted by a $78 million after-tax gain on the sale of certain hydroelectric facilities in February 2014, and lower coal and transportation contract settlement and termination costs.

Revenues —

Total revenues decreased $633 million in the first six months of 2015, compared to the same period of 2014, primarily due to decreased sales volumes in line with CES' strategy to more effectively hedge its generation. 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:

Six Months Ended June 30,

Revenues by Type of Service	2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$717	$1,332	$(615)
Governmental Aggregation	506	597	(91)
Mass Market	160	242	(82)
POLR	445	469	(24)
Structured Sales	259	215	44
Total Contract Sales	2,087	2,855	(768)
Wholesale	347	162	185
Transmission	93	152	(59)
Other	104	95	9
Total Revenues	$2,631	$3,264	$(633)

MWH Sales by Channel	Six Months Ended June 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	13,319	24,672	(46.0)%
Governmental Aggregation	8,052	10,421	(22.7)%
Mass Market	2,340	3,630	(35.5)%
POLR	7,742	8,287	(6.6)%
Structured Sales	5,897	6,155	(4.2)%
Total Contract Sales	37,350	53,165	(29.7)%
Wholesale	867	32	2,609.4 %
Total MWH Sales	38,217	53,197	(28.2)%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(613)	$(2)	$—	$—	$(615)
Governmental Aggregation	(135)	44	—	—	(91)
Mass Market	(86)	4	—	—	(82)
POLR	(30)	6	—	—	(24)
Structured Sales	(9)	53	—	—	44
Wholesale	31	(5)	6	153	185

Lower sales volumes in the Direct, Governmental Aggregation, and Mass Market sales channels primarily reflect CES' efforts to reposition its sales portfolio by reducing exposure to weather sensitive load. Although unit pricing was higher year-over-year in the 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. Direct unit prices were lower, resulting from ancillary pass-through revenues

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recognized in 2014 associated with PJM expenses incurred in January 2014, partially offset by the higher rates associated with increased capacity expense.

The decrease in POLR sales of $24 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $44 million primarily due to market conditions that increased the gains on various structured financial sales contracts, partially offset by lower structured transaction volumes.

Wholesale revenues increased $185 million, primarily due to an increase in capacity revenue from higher capacity prices and an increase in short-term (net hourly positions) transactions, which were limited by low spot market energy prices.

Transmission revenue decreased $59 million in the first six months of 2015 as compared to the same period of 2014 primarily due to lower congestion revenue resulting from market conditions related to extreme weather events in 2014.

Other revenue increased $9 million primarily due to a $3 million pre-tax gain on the sale of property to a regulated affiliate and higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks in November of 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $1,009 million in the first six months of 2015 due to the following:

- Fuel costs decreased $255 million primarily due to lower volumes associated with lower economic dispatch of fossil units resulting from low wholesale spot market energy prices. Lower nuclear unit prices also contributed to the decrease, resulting from the suspension of the DOE nuclear disposal fee, which became effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. Terminations and settlements of coal and transportation contracts resulted in a pre-tax gain of approximately $1 million and a pre-tax loss of $85 million in the first six months of 2015 and 2014, respectively.
- Purchased power costs decreased $499 million due to lower volumes ($594 million) and lower unit prices ($14 million), partially offset by higher capacity expenses ($109 million). Lower volumes were primarily due to decreased load requirements resulting from CES' sales strategy, partially offset by decreased fossil generation discussed above. The decrease in unit prices was primarily a result of the market conditions associated with the extreme weather events in January 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.

- Fossil operating costs decreased $10 million primarily due to fewer planned and unplanned outages for the six months ended June 30, 2015 as compared to the same period of 2014, partially offset by higher employee benefit expense.

- Nuclear operating costs increased $20 million as a result of higher employee benefit expense and higher outage costs.

- Transmission expenses decreased $165 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in January 2014, of which a portion were passed through to commercial and industrial customers, as discussed above.
- Depreciation expense increased $8 million as a result of a higher asset base from projects such as MATS compliance and the Davis-Besse steam generator replacement completed in May 2014.
- General taxes decreased $16 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

- Other operating expenses decreased $92 million primarily due to a $58 million decrease in retail-related costs and a $50 million decrease in mark-to-market expenses on commodity contract positions, partially offset by a $16 million impairment associated with transportation equipment during the second quarter of 2015.

Other Expense —

Total other expense in the first six months of 2015 increased $27 million compared to the same period of 2014 primarily due to lower investment income and higher OTTI on NDT investments, higher interest expense, and lower capitalized interest, partially offset by the absence of an $8 million loss on debt redemptions incurred in the first six months of 2014.

Discontinued Operations —

Discontinued operations decreased operating results $86 million in the first six months of 2015 compared to the same period of 2014 primarily due to 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 34.4% and 36.2% for the first six months of 2015 and 2014, respectively. The decrease in the effective tax rate primarily resulted from tax benefits recognized in the second quarter of 2014 associated with changes in state apportionment factors.

Corporate / Other — First Six Months of 2015 Compared with First Six Months of 2014

Financial results from other operating segments and reconciling items resulted in a $38 million decrease in net income in the first six months of 2015 compared to the same period of 2014 primarily due to higher interest expense and a lower effective tax rate on pre-tax losses. The increased interest expense primarily relates to a new $1 billion term loan to FE in March of 2014, a gain recorded on the termination of interest rate swap arrangements in the second quarter of 2014 and higher short-term borrowings in the first six months of 2015 as compared to the same period of 2014. The decrease in the effective tax rate on pre-tax losses is primarily due to tax benefits recognized in 2014 from the elimination of certain future tax liabilities associated with basis differences and changes in state apportionment factors and an increase in uncertain tax benefits recognized in 2015.

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of June 30, 2015 and December 31, 2014, and the changes during the six months ended June 30, 2015:

Regulatory Assets (Liabilities) by Source	June 30, 2015	December 31, 2014	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$210	$240	$(30)
Customer receivables for future income taxes	373	370	3
Nuclear decommissioning and spent fuel disposal costs	(292)	(305)	13
Asset removal costs	(251)	(254)	3
Deferred transmission costs	102	90	12
Deferred generation costs	262	281	(19)
Deferred distribution costs	358	182	176
Contract valuations	141	153	(12)
Storm-related costs	451	465	(14)
Other	169	189	(20)
Net Regulatory Assets included on the Consolidated Balance Sheets	$1,523	$1,411	$112

Regulatory assets that do not earn a current return totaled approximately $154 million and $488 million as of June 30, 2015 and December 31, 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to storm damage costs of $329 million began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant in service to regulatory assets, which is being recovered over five years.

As of June 30, 2015 and December 31, 2014, FirstEnergy had approximately $161 million and $243 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy’s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2015 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

Capital expenditures for 2015 are expected to be approximately $2.9 billion. These capital expenditures, including the transmission expansion program discussed below, are expected to be funded with a combination of debt, cash savings from equity issuances through the stock investment plan and, to the extent available, employee benefit plans, and the projected $320 million annually in cash preserved as a result of the dividend action taken in January 2014.

FirstEnergy's strategy is to focus on growth through investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion “Energizing the Future” transmission expansion plan that began in 2014 and will continue through 2017 to upgrade and expand the transmission system owned by FirstEnergy’s Regulated Transmission segment. This program is focused on projects that enhance system performance and physical security and add operating flexibility and capacity, starting with the ATSI system and moving east across FirstEnergy's service territory over time. FirstEnergy expects to fund these investments through a combination of debt and cash, including from previously announced equity issuances through a stock investment plan. In the future, FirstEnergy may consider additional equity to fund capital investments in the regulated operations. Regulated Transmission's capital expenditure forecast for 2015 is approximately $970 million, of which $599 million was incurred through the first six months of 2015. In total, FirstEnergy has identified at least $15 billion in incremental transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017.

The Utilities and FirstEnergy's competitive generation operations expect to fund their capital expenditures over the next several years through cash from operations, debt, and, depending on the operating company, equity contributions from FE. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, subject to market and other conditions.

In alignment with FirstEnergy’s strategy to invest in its Regulated Transmission and Regulated Distribution segments and the reposition of the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at each business unit, and maintaining strong liquidity for an overall stable financial position. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

FirstEnergy completed its cash flow improvement plan to identify both immediate and long-term savings opportunities. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three year period.

Any financing plans by FirstEnergy, including refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

As of June 30, 2015, 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 June 30, 2015, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs[(1)]	$92

Unsecured notes	300
FMBs	215
Unsecured PCRBs[(1)]	537
Collateralized lease obligation bonds	47
Sinking fund requirements	86
Other notes	15
	$1,292

(1) These PCRBs are classified as currently payable long-term debt because the applicable interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings

FirstEnergy had $2,908 million and $1,799 million of short-term borrowings as of June 30, 2015 and December 31, 2014, respectively. FirstEnergy's available liquidity as of June 30, 2015, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$3,500	$894
FES / AE Supply	Revolving	March 2019	1,500	1,202
FET[2]	Revolving	March 2019	1,000	950
		Subtotal	$6,000	$3,046
		Cash	—	90
		Total	$6,000	$3,136

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

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities) expiring on March 31, 2019.

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities, as amended) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of June 30, 2015:

Borrower	FE Revolving Credit Facility Sublimit	FES/AE Supply Revolving Credit Facility Sublimit	FET Revolving Credit Facility Sublimit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)				
FE	$3,500	$—	$—	$—	(1)
FES	—	1,500	—	—	(2)
AE Supply	—	1,000	—	—	(2)
FET	—	—	1,000	—	(1)
OE	500	—	—	500	(3)
CEI	500	—	—	500	(3)
TE	500	—	—	500	(3)
JCP&L	600	—	—	850	(3)
ME	300	—	—	500	(3)
PN	300	—	—	300	(3)
WP	200	—	—	200	(3)
MP	500	—	—	500	(3)

PE	150	—	—	150	(3)
ATSI	—	—	500	500	(3)
Penn	50	—	—	50	(3)
TrAIL	—	—	400	400	(3)

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
(3) Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $600 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sublimit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

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

As of June 30, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

Term Loans

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan, due May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of June 30, 2015, FE was in compliance with the applicable debt to total capitalization ratios under each of these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rates for borrowings in the first six months of 2015 were 0.97% per annum for the regulated companies' money pool and 1.61% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of June 30, 2015, FirstEnergy’s currently payable long-term debt included approximately $92 million (all applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of June 30, 2015 were issued by the following bank:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	$92	March 2017	March 2017

[1] Excludes approximately $1 million of applicable interest coverage.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE’s and its subsidiaries’ credit ratings as of June 30, 2015:

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

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of June 30, 2015, FE and its subsidiaries could issue additional debt of approximately $4 billion and remain within the limitations of the financial covenants required by the Facilities. As of June 30, 2015, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $4 billion given FE's consolidated debt to total capitalization ratio under its Facility.

Changes in Cash Position

As of June 30, 2015, FirstEnergy had $94 million of cash and cash equivalents compared to $85 million of cash and cash equivalents as of December 31, 2014. As of June 30, 2015 and December 31, 2014, FirstEnergy had approximately $75 million and $79 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

Net cash provided from operating activities was $990 million during the first six months of 2015 compared with $622 million provided from operating activities during the first six months of 2014. Cash flows from operations increased $368 million in the first six months of 2015 compared with the same period of 2014 primarily due to higher earnings from continuing operations and lower posted collateral, partially offset by a $143 million contribution to the qualified pension plan and a year-over-year decline in working capital primarily due to the timing of payments to vendors.

Cash Flows From Financing Activities

In the first six months of 2015, cash provided from financing activities was $712 million compared to $805 million during the first six months of 2014. The following table summarizes new debt financing, redemptions and repayments:

Securities Issued or Redeemed / Repaid	Six Months Ended June 30, 2015	2014
	(In millions)	
New Issues		
PCRBs	$—	$637
Term Loan	200	1,050
Unsecured Notes	—	1,450
	$200	$3,137
Redemptions / Repayments		
PCRBs	$—	$(682)
Term Loan	(200)	—
Senior secured notes	(92)	(93)
Unsecured notes	—	(150)
	$(292)	$(925)
Short-term borrowings (repayments), net	$1,109	$(1,081)
Common stock dividend payments	$(303)	$(302)

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan, maturing on May 29, 2020.

Also during the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The sales are expected to settle on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of WP FMBs will be used to repay short-term borrowings including those under the FirstEnergy regulated money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs will be used to repay its currently outstanding $145 million aggregate principal amount of 5.125% FMBs maturing on August 15, 2015. There can be no assurance that each of WP and PE will satisfy all the conditions necessary to close and settle their respective FMB transactions.

On July 1, 2015 FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBS were remarketed with the fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

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Cash Flows From Investing Activities

Cash used for investing activities in the first six months of 2015 principally represented cash used for property additions. The following table summarizes investing activities for the first six months of 2015 and the comparable period of 2014:

	Six Months Ended June 30,		
Cash Used for Investing Activities	2015	2014	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$592	$609	$(17)
Regulated Transmission	551	601	(50)
Competitive Energy Services	317	558	(241)
Other and reconciling adjustments	26	41	(15)
Nuclear fuel	97	58	39
Proceeds from asset sales	(10)	(394)	384
Investments	62	57	5
Asset removal costs	67	47	20
Other	(9)	(8)	(1)
	$1,693	$1,569	$124

Net cash used for investing activities during the first six months of 2015 increased by $124 million compared to the same period of 2014 primarily due to $394 million of proceeds received from the sale of hydroelectric assets in 2014, partially offset by a decrease in property additions mainly at CES associated with the Davis-Besse steam generators that were placed into service in May 2014.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy and its subsidiaries could be required to make under these guarantees as of June 30, 2015, was approximately $3.9 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]	$54
Deferred compensation arrangements	525
Other[2]	20
	599
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts[3]	177
FES' guarantee of NG's nuclear property insurance	98
FES' guarantee of nuclear decommissioning costs[4]	174
FES' guarantee of FG's sale and leaseback obligations	1,796
	2,245
FE's Guarantees on Behalf of Business Ventures	
Global Holding facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	442
Surety Bonds	23
FES' LOC (long-term tax-exempt debt)[5]	93
LOCs[6]	159
	717
Total Guarantees and Other Assurances	$3,861

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

(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $9 million for railcar leases and $7 million for various leases.

(3) Includes Energy and Energy-Related Contracts associated with FES of approximately $173 million.

(4) As of July 30, 2015, this amount was reduced to $20.5 million.

(5) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with maturities in 2017 and the principal amount of floating-rate PCRBs of $92 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(6) Includes $55 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $88 million issued in connection with energy and energy related contracts, $2 million issued in connection with railcar leases, $8 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $6 million pledged in connection with the sale and leaseback of Perry 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 exposures as of June 30, 2015, FES has posted collateral, including LOC, of $214 million. The Regulated Distribution segment has posted collateral of $1 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.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of June 30, 2015:

Collateral Provisions	FES (In millions)	AE Supply	Utilities	Total
Split Rating (One rating agency's rating below investment grade)	$410	$6	$50	$466
BB+/Ba1 Credit Ratings	$447	$6	$50	$503
Full impact of credit contingent contractual obligations	$492	$16	$50	$558

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of June 30, 2015, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $13 million with affiliated parties.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. The facility, which was originally entered into in October 2012 with a $350 million borrowing that was subsequently paid down to the current $300 million, was amended and extended in the first quarter of 2015 as further discussed below. 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.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 6, Variable Interest Entities, for additional information regarding FEV's investment in Global Holding.

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 $1 billion as of June 30, 2015, and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

As of June 30, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

MARKET RISK INFORMATION

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

Commodity Price Risk

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

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 7, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative contracts assets and liabilities as of June 30, 2015 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2015	2016	2017	2018	2019	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(6)	$—	$—	$—	$—	$—	$(6)
Other external sources[2]	(27)	(18)	(13)	(21)	—	—	(79)
Prices based on models	3	6	—	—	(20)	(3)	(14)
Total[3]	$(30)	$(12)	$(13)	$(21)	$(20)	$(3)	$(99)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(140) million in non-hedge derivative contracts related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of June 30, 2015, not subject to regulatory accounting, a 10% adverse change in commodity prices would increase net income by approximately $25 million during the next 12 months.

Equity Price Risk

As of June 30, 2015, the FirstEnergy pension plan assets were allocated approximately as follows: 44% in equity securities, 34% in fixed income securities, 10% in absolute return strategies, 8% in real estate and 4% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the six months ended June 30, 2015, FirstEnergy made a $143 million contribution to its qualified pension plan. See Note 3, Pension and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. Through June 30, 2015, FirstEnergy's pension plan assets incurred losses of approximately (0.9)% as compared to an annual expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of June 30, 2015, approximately 68% of the funds were invested in fixed income securities, 29% of the funds were invested in equity securities and 3% 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 $1,596 million, $697 million and $61 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2015, excluding $(6) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $70 million reduction in fair value as of June 30, 2015. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy’s NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the six months ended June 30, 2015, FirstEnergy contributed approximately $15 million to the NDT.

Interest Rate Risk

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year. A primary factor contributing to these actuarial gains and losses are changes in the discount rates used to value pension and OPEB obligations as of the measurement date of December 31 and the difference between expected and actual returns on the plans' assets. At this time, FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 2015.

CREDIT RISK

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

Wholesale Credit Risk

FirstEnergy and FES measure 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 and FES have a legally enforceable right of offset. FirstEnergy and FES monitor and manage 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 and FES' energy contract counterparties maintain investment-grade credit ratings.

Retail Credit Risk

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

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

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's and FES' 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 by 10% and reduce electricity demand by 15%, in each case by 2015, 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. The projected costs of the 2015-2017 plan are approximately $64 million for that three year period, of which $9 million was incurred through June 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2016 and beyond, beginning with the goal of 0.2% for 2016 and ramping up thereafter to reach 2%. 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 (the February 27 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. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. 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 27 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 27 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. The Staff of the MDPSC also recommended 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 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 March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC has set an initial hearing on the Staff of the MDPSC's analysis and recommendations for September 1-2, 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC’s regulations. The MDPSC has scheduled a hearing on the reports filed by PE and the other electric utilities in Maryland for August 24, 2015.

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.

On March 26, 2015, the NJBPU entered final orders which together provide an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding filed in November 2012 directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed, including a study related to reliability. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such study, which will include operational and financial components and is expected to take approximately one year to complete.

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: 1) calculating savings using a 5 year look back from the beginning of the test year; 2) allocating savings with 75% retained by the company and 25% allocated to rate payers; and 3) 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 has filed to participate as a respondent in that proceeding, which remains pending.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies primarily operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The matter has not yet been scheduled for oral argument.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled Powering Ohio's Progress. The Ohio Companies initially requested a decision by the PUCO by April 8, 2015. The Ohio Companies filed a partial Stipulation and Recommendation on December 22, 2014, a Supplemental Stipulation and Recommendation on May 28, 2015, and a Second Supplemental Stipulation and Recommendation on June 4, 2015. The evidentiary hearing on the ESP IV is now scheduled to commence on August 31, 2015.

The material terms of the proposed plan as filed include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continuing collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Providing economic development and assistance to low-income customers for the three-year plan period;
- An Economic Stability Program providing for a retail rate stability rider to flow through charges or credits representing the net result of the costs paid to FES through a proposed 15-year purchase power agreement for the output of Sammis, Davis-Besse and FES’ share of OVEC against the revenues received from selling the output into the PJM markets over the same period;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;

- Continuing Rider DCR with increased revenue caps of approximately $30 million per year that allows continued investment supporting the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including appropriately such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings; and
- General updates to electric service regulations and tariffs to reflect regulatory orders, administrative rule changes, and current practices.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to the outcome of a legislative study committee. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to the outcome of a legislative study committee.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

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, subject to the outcome of a legislative study committee, 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 part of the purchases arising from one auction and directing 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. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013. 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. The matter remains pending.

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.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over 29-months concluding in the second quarter of 2013. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. The United States District Court for the Eastern District of Pennsylvania granted the PPUC's motion to dismiss the complaint filed by ME and PN to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. As a result of the U.S. District Court's decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013. On appeal, in a split decision, two judges of a three-judge panel of the Third Circuit affirmed the U.S. District Court's dismissal of the complaint, agreeing that ME and PN had litigated the issue in the state proceedings and thus were precluded from subsequent litigation in federal court. ME and PN timely filed for rehearing and rehearing en banc; the Third Circuit rejected that rehearing request. ME and PN filed a Petition for Certiorari with the United States Supreme Court on February 12, 2015, and that Court denied the Petition on May 26, 2015.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008), the PPUC was charged with reviewing the cost effectiveness of all Pennsylvania EDC's energy efficiency and peak demand reduction programs. In 2012, the PPUC found the energy efficiency programs to be cost effective and directed all of the EDCs in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. At that time, the PPUC deferred ruling on the need to create peak demand reduction targets and did not include a peak demand reduction requirement in the Phase II plans. On March 14, 2013, the PPUC adopted a settlement among the Pennsylvania Companies and interested parties and approved the Pennsylvania Companies' Phase II EE&C Plans. Total costs of these plans are expected to be approximately $234 million and 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. EDCs are permitted to recover costs for implementing Phase III EE&C plans.

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings requested approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. On February 3, 2015, each of the Pennsylvania Companies filed a Joint Petition for Settlement seeking PPUC approval of the agreements reached in each proceeding which, among other things, provided for an increase in annual revenues of $292.8 million ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP). The sole issue reserved for briefing was with respect to the scope and pricing of the Companies' proposed LED offerings. Recommended Decisions were issued by the ALJs recommending approval of the settlements and implementation of the Pennsylvania Companies' LED lighting offerings as proposed in their original filings. On April 9, 2015, the PPUC adopted the ALJs' Recommended Decisions and approved the settlements. The settlements will result in $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 revised implementation plans regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. On May 19, 2015, the PPUC granted a forty-five day extension for the filing of revised implementation plans with respect to certain of the matters raised in its March 30, 2015 Order. On May 29, 2015 and July 13, 2015, the Pennsylvania Companies filed their revised implementation plan. The cost of compliance is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provides for: a $15 million increase in base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a 5-year period approximately $46 million of storm restoration costs; and elimination of the Temporary Transaction Surcharge for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates. MP and PE's current ENEC rates went into effect on February 25, 2015, in accordance with a settlement approved by the WVPSC on January 29, 2015.

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

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new 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 most recently 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. Settlement discussions under a FERC-appointed settlement judge are ongoing.

The PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between the PJM Region and: (1) the NYISO region; (2) the MISO region; and (3) the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the costs of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region, or, in the case of MISO, indicate that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. As of May 14, 2015, FERC has accepted the PJM/NYISO, PJM/MISO and PJM/SERTP filings, subject to further compliance requirements. FERC’s acceptance of the PJM/SERTP filing is also subject to refund and the SERTP region participants’ related Order No. 1000 interregional compliance proceedings.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent “right of first refusal” to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM’s RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No.1000 compliance filing.

The outcome of the remaining pending proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

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 move. 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. FirstEnergy's request for rehearing of FERC's order remains pending.

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. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. On April 22, 2015, certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC’s prior ruling rejecting MISO’s proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. Reply comments were filed June 22, 2015. The matter is now before FERC for consideration.

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 those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an “historical looking” approach, where transmission rates reflect actual costs for the prior year, to a “forward looking” approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. Several parties protested ATSI's filing. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings. FERC also initiated an inquiry pursuant to Section 206 of the FPA into ATSI's ROE and certain other matters, with a refund effective date of January 12, 2015, for any refund resulting from the inquiry. On July 20, 2015, ATSI and certain parties filed a settlement agreement with FERC, which remains subject to FERC approval. The agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: i) 12.38% for the period commencing January 1, 2015 through June 30, 2015; ii) 11.06% for the period commencing July 1, 2015 through December 31, 2015; iii) 10.38% for the period commencing January 1, 2016. The 10.38% ROE value shall remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2018. The agreement currently is pending at FERC and ATSI anticipates that it will be approved later this year.

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. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable: of (i) a lease of real property and rights associated with the utilities' transmission assets to MAIT; (ii) a Mutual Assistance Agreement; (iii) that MAIT be deemed a public utility; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) approval of certain affiliated interest agreements. If approved, JCPL, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. FERC approval is expected within six months with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective asset contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011. The California Parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit issued a decision remanding the case to FERC for further proceedings.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

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 (an equity method investment for FE), 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 hearing if the parties do 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. The hearing concluded on April 22, 2015, and post-hearing briefing is ongoing.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC’s ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the “zone of reasonableness” that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England Inc. transmission owners. On March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggested that FERC address the remaining concerns in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. In January 2015, the RTOs and affected parties indicated to FERC that discussions on the various issues are continuing. At FERC's direction, on May 12 and 13, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam, including capacity portability, to assist the FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 and Lakeshore Unit 18 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer of Eastlake Units 1-3 was completed on April 30, 2015 and ATSI completed the conversion of Eastlake Unit 3 to a synchronous condenser in June 2015. ATSI expects to complete the conversion for Units 1 and 2 by mid 2016.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in “underfunding” of FTR payments. FES and AE Supply continue to evaluate proposals to address issues with FTR allocation and funding.

On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the new complaint and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

A recent and related issue is the effect that certain financial trades have on congestion. On August 29, 2014, FERC instituted an investigation to address the question of whether the current rules regarding “Up-to Congestion” transactions are just and reasonable. FESC, on behalf of FES and the Utilities, filed comments supporting the investigation, arguing that PJM Tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase. FERC convened a technical conference on January 7, 2015 to discuss application of certain FTR-related rules to Up-to Congestion and virtual transactions and whether PJM’s current uplift allocation for Up-to Congestion and virtual transactions is just and reasonable. FERC action following the technical conference is pending.

PJM Market Reform: 2014 PJM RPM Tariff Amendments

In late 2013 and early 2014, PJM submitted a series of amendments to the PJM Tariff to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. PJM's filings can be grouped into four categories: (i) DR; (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. In each of the relevant dockets, FirstEnergy and other parties submitted comments largely supporting PJM's proposed amendments. FERC largely approved the PJM Tariff amendments as proposed by PJM regarding DR, imports, and transmission upgrade modeling. Compliance filings pursuant to and requests for rehearing of certain of these orders are pending before FERC. However, FERC rejected the arbitrage/capacity replacement amendments, directing instead that a technical conference be convened to further examine the issues. The technical conference has yet to be scheduled, but the issue of arbitrage has been raised in other ongoing FERC proceedings.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed “Capacity Performance” reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance and energy market reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC’s order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.
Following FERC's issuance of the June 9, 2015 order on the Capacity Performance proposal, PJM announced that it will conduct the 2015 BRA for the 2018/2019 delivery year on August 10-14, 2015. In response to a subsequent complaint, on July 22, 2015, FERC issued an order directing PJM to permit DR and energy efficiency resources to participate in the Capacity Performance transition auctions. As a result of FERC’s order, PJM will conduct the Capacity Performance transition auction for the 2016/2017 delivery year on August 26-27, 2015, with the results to be announced on August 31, 2015. In addition, PJM will conduct the Capacity Performance transition auction for the 2017/2018 delivery year on September 3-4, 2015 with the results to be announced on September 9, 2015.
FirstEnergy and other PJM market entities also are addressing PJM’s capacity market concerns in other FERC proceedings. On November 20, 2014, FERC issued an order directing each ISO/RTO to file a report with FERC outlining each region’s efforts to ensure fuel security. PJM filed its report on February 18, 2015, advising FERC that PJM’s Capacity Performance proposal will address fuel assurance issues. On March 20, 2015, FESC, on behalf of its affected affiliates and as part of a coalition, filed responsive comments demonstrating that significant improvements were needed for PJM’s Capacity Performance proposal to address fuel assurance issues. The comments are before FERC for review.

PJM Market Reform: PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM Tariff describes the rules for calculating the “offer cap” for each unit that offers into the RPM auctions. FES disagreed with the PJM Market Monitor's approach for calculating the offer caps and in 2014, FES asked FERC to determine which PJM Tariff interpretation, FES' or the PJM Market Monitor's, was correct. On August 25, 2014, FERC issued a declaratory order agreeing with the FES interpretation of the PJM Tariff language. FERC went on, however, to initiate a new proceeding to examine whether the existing PJM Tariff language is just and reasonable. PJM filed its brief explaining why the existing PJM Tariff language is just and reasonable. Other parties, including FES, submitted responsive briefs. The briefs and related pleadings are pending before FERC.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On May 4, 2015, the United States Supreme Court granted petitions for certiorari requesting review of the May 23, 2014 opinion, and the proceeding is in the briefing phase. The U.S. Court of Appeals for the D.C. Circuit is withholding issuance of its mandate pending the United States Supreme Court's review on the merits.

On May 23, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful in light of the May 23, 2014 U.S. Court of Appeals for the D.C. Circuit decision discussed above. FESC, on behalf of FES, subsequently filed an amended complaint renewing its request that DR be removed from the May 2014 BRA. Specifically, FESC requested that FERC direct PJM to recalculate the results of the May 2014 BRA by: (i) removing DR from the PJM capacity supply pool; (ii) leaving the offers of actual capacity suppliers unchanged; and then (iii) determining which capacity suppliers clear the auction on the basis of the offers they submitted consistent with the existing PJM Tariff once the unlawful DR resources have been removed. The complaint remains pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

PJM Market Reform: PJM 2014 Triennial RPM Review

The PJM Tariff obligates PJM to perform a thorough review of its RPM program every three years. On September 25, 2014, PJM filed proposed changes to the PJM Tariff as part of the latest review cycle. Among other adjustments, the filing included: (i) shifting the VRR curve one percentage point to the right, which would increase the amount of capacity supply that is procured in the RPM auctions and the clearing price; and (ii) a change to the index used for calculating the generation plant construction costs of the Net CONE formula for the future years between triennial reviews. On November 28, 2014, FERC accepted the PJM Tariff amendments as proposed, subject to a minor compliance requirement. PJM subsequently submitted the required compliance filing. On December 23, 2014, a coalition including FESC, on behalf of its affected affiliates, requested rehearing of FERC's order. PJM's compliance filing, and the coalition's and others' requests for rehearing, 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. Depending on how the EPA and the states implement the CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

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. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a D.C. Circuit decision that upheld MATS, rejecting EPA’s regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the D.C. Circuit for further proceedings. Subject to the outcome of further proceedings before the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $370 million (CES segment of $178 million and Regulated Distribution segment of $192 million), of which $167 million has been spent through June 30, 2015 ($62 million at CES and $105 million at Regulated Distribution).

Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

FirstEnergy and FES have various long-term coal supply and transportation agreements, some of which run through 2025 and certain of which are related to deactivated coal-fired plants. FirstEnergy and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties for the agreements associated with the deactivated plants and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses, do not excuse or otherwise mitigate the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FirstEnergy and FES are unable to estimate the loss or range of loss. As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going 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, and March 27, 2013, 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 possible loss or range of loss.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the United States District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG has entered into a confidential settlement to resolve these claims for an immaterial amount.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (1) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President’s Climate Action Plan goals both in terms of timing and reduction levels.

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. EPA proposed a new source performance standard in September 2013, which would not apply to any existing, modified, or reconstructed fossil fuel fired generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. EPA proposed regulations in June 2014, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by June 30, 2016, to meet EPA's state specific CO_2 emission rate goals. EPA's proposal allows states to request a 1-year extension for SIPs (June 30, 2017) or a 2-year extension for multi-state SIPs (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel fired electric generating units. 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 EPA to install GHG control technologies. On June 9, 2015, the U.S. Court of Appeals for the D.C. Circuit denied challenges to prevent EPA from regulating CO_2 emissions from existing fossil fuel fired electric generating units because EPA's proposed Clean Power Plant is not final agency action and therefore not ripe for review. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

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. In advance of the December 2015 United Nations Framework Convention on Climate Change meetings in Paris, 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. 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 significant 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 costs of compliance with these standards may require material capital expenditures.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a United States District Court and the treatment obligations are proposed to phase-in as permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule and any final action taken by the states, the future costs of compliance with these standards may require material capital expenditures.

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 possible 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. Depending on how the final rules are ultimately implemented, the future costs of compliance with such CCR regulations may require material capital expenditures.

The PA DEP filed a 2012 complaint against FG in the United States District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCR Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified consent decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE 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 Bruce Mansfield plant is pursuing several options for its CCRs following December 31, 2016. A June 28, 2013 complaint filed by Citizens Coal Counsel and other NGOs in the United States District Court for the Western District of Pennsylvania, against the owner and operator of a reclamation mine in LaBelle, Pennsylvania that is one possible alternative, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site. To date, no complaint has been filed. On May 22, 2015, PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility, another potential alternative for Bruce Mansfield plant CCR disposal. On July 6, 2015, Sierra Club filed a Notice of Appeal with the Pennsylvania Environmental Hearing Board challenging the renewal and reissuance of the permit for the Hatfield’s Ferry CCB disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of June 30, 2015 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 $134 million have been accrued through June 30, 2015. Included in the total are accrued liabilities of approximately $93 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 possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of June 30, 2015, FirstEnergy had approximately $2.3 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 guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted an opportunity for a hearing on the Davis-Besse license renewal application to a group of Intervenors, subject to the admissibility of contentions. On March 10, 2015, the ASLB issued an Order that terminated its jurisdiction and closed the record in the Davis-Besse license renewal proceeding. On June 9, 2015, the NRC Commissioners denied an intervenor's filed requests to reopen the record and admit a contention on the NRC’s Continued Storage Rule.

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.

The NRC continues to evaluate FENOC's analysis of 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. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal for failure to supply coal required by a long term CSA. A jury trial, appeal and other proceedings followed. On April 6, 2015, and in lieu of further appeals and litigation process, the parties agreed to a full and final settlement of all remaining claims and on April 7, 2015, ICG paid the $15 million settlement amount in full of which $12 million was allocated to AE Supply and $3 million to MP. The trial and appellate courts were notified of the settlement and the cases were discontinued by the parties.

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 9, 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.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle 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. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. This standard is currently effective for fiscal years beginning after December 15, 2016, with no early adoption permitted, and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. In July 2015, the FASB voted to proceed with a one-year deferral of the revenue recognition standard for all entities, with early adoption as of the original effective date permitted. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In April 2015, the FASB issued, "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 guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FE. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy’s fossil and hydroelectric generation facilities (excluding AE Supply and MP), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG and 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' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States. In 2014, FES began reducing its exposure to weather-sensitive loads, maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams and modifying its hedging strategy to optimize risk management and market upside opportunities. As part of this, FES has eliminated future selling efforts in certain sales channels, such as Mass Market, medium commercial-industrial and select large commercial-industrial (Direct), to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility as was experienced in the first quarter of 2014. In 2015 and going forward, FES expects to target approximately 65 to 75 million MWHs in annual contract sales with a projected target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct),10 to 20 million MWHs in block wholesale sales, including Structured sales, and 10 to 20 million MWHs of spot wholesale sales committed. As of June 30, 2015, committed sales for calendar year 2015, 2016 and 2017 are 72 million MWHs, 53 million MWHs, and 31 million MWHs, respectively. Support for current customers in the channels to be exited will remain through their respective contract terms.

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

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

Results of Operations

Operating results increased $50 million in the first six months of 2015, compared to the same period of 2014. In the first six months of 2014, FES sold certain hydroelectric power stations resulting in an after-tax gain of $110 million. Excluding this gain, year-over-year operating results improved primarily from higher capacity revenue associated with higher capacity auction prices and the absence of the extreme market conditions and unplanned outages in January 2014 resulting in higher costs to serve contract sales. Subsequent to the first quarter of 2014, FES began to reduce its exposure to weather-sensitive loads and more effectively hedge its generation. As a result of that revised strategy, FES was able to successfully mitigate the extreme weather conditions that occurred in February 2015 by more effectively using its generation to supply higher customer usage as compared to 2014 when FES purchased power at higher prices to supply increased customer usage.

Revenues -

Total revenues decreased $785 million, in the first six months of 2015, compared to the same period of 2014, primarily due to decreased sales volumes in line with FES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices as a result of the change in sales channel mix and increased channel pricing as well as higher capacity revenues, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$717	$1,329	$(612)
Governmental Aggregation	506	597	(91)
Mass Market	160	242	(82)
POLR	445	461	(16)
Structured Sales	246	202	44
Total Contract Sales	2,074	2,831	(757)
Wholesale	244	234	10
Transmission	83	134	(51)
Other	95	82	13
Total Revenues	$2,496	$3,281	$(785)

MWH Sales by Channel	Six Months Ended June 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	13,319	24,622	(45.9)%
Governmental Aggregation	8,052	10,421	(22.7)%
Mass Market	2,340	3,630	(35.5)%
POLR	7,742	8,135	(4.8)%
Structured Sales	5,673	5,934	(4.4)%
Wholesale	161	—	100.0%
Total MWH Sales	37,287	52,742	(29.3)%

The following table summarizes the price and volume factors contributing to changes in revenues in the first six months of 2015 compared with the same period of 2014:

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(610)	$(2)	$—	$—	$(612)
Governmental Aggregation	(135)	44	—	—	(91)
Mass Market	(86)	4	—	—	(82)
POLR	(22)	6	—	—	(16)
Structured Sales	(9)	53	—	—	44
Wholesale	3	—	(109)	116	10

The Direct, Governmental Aggregation and Mass Market customer base was 1.9 million as of June 30, 2015, compared to 2.6 million as of June 30, 2014, reflecting FES' efforts to reposition its sales portfolio as discussed above. Additionally, although unit pricing was higher year-over-year in the 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. Direct unit prices were lower, resulting from ancillary pass-through revenues recognized in 2014 associated with PJM expenses incurred in January 2014, partially offset by the higher rates associated with increased capacity expense.

The decrease in POLR sales of $16 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $44 million primarily due to market conditions that increased the gains on various structured financial sales contracts, partially offset by lower structured transaction volumes.

Wholesale revenues increased $10 million due to an increase in capacity revenue from higher capacity prices, partially offset by lower net gains on financially settled contracts, primarily with AE Supply. Additionally, although wholesale short-term transactions increased year-over-year, low average spot market energy prices reduced the economic dispatch of fossil generating units, limiting additional wholesale sales volumes.

Transmission revenue decreased $51 million in the first six months of 2015 as compared to the same period of 2014 primarily due to lower congestion revenue resulting from market conditions related to extreme weather events in 2014.

Other revenue increased $13 million primarily due to a $3 million pre-tax gain on the sale of property to a regulated affiliate and higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks in November of 2014. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses decreased by $1,096 million in the first six months of 2015 compared to the same period of 2014.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first six months of 2015 compared with the same period of 2014:

	Source of Change Increase (Decrease)				
Operating Expense	Volumes	Prices	Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(130)	$(20)	$(79)	$—	$(229)
Nuclear Fuel	7	(10)	—	—	(3)
Affiliated Purchased Power	(5)	—	13	—	8
Non-affiliated Purchased Power(1)	(968)	(338)	486	108	(712)

(1) In the first six months of 2014, losses on financially settled wholesale sales contracts of $337 million resulting from higher market prices were netted in purchased power.

Fossil and nuclear fuel costs decreased $232 million primarily due to a decrease in fossil generation volumes related to lower economic dispatch of fossil units resulting from low wholesale spot market energy prices, partially offset by a slight increase in nuclear generation. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal contracts. In the first six months of 2015, a pre-tax gain of approximately $12 million was recognized associated with the elimination of an obligation under an existing coal contract. In the first six months of 2014, a termination of a coal contract associated with deactivated plants resulted in a pre-tax loss of $67 million.

Non-affiliated purchased power costs decreased $712 million due to lower volumes ($726 million) and decreased prices ($94 million), partially offset by higher capacity expenses ($108 million). Lower volumes were primarily due to decreased load requirements resulting from FES' sales strategy, partially offset by decreased fossil generation discussed above. The decrease in unit prices was primarily a result of the market conditions associated with the extreme weather events in January 2014. The increase in capacity expense, which is a component of FES' retail price, was primarily the result of higher capacity rates associated with FES' retail sales obligations.

Other operating expenses decreased $154 million in the first six months of 2015, compared to the same period of 2014 primarily due to the following:

- Fossil operating costs decreased $7 million primarily due to fewer planned and unplanned outages for the six months ended June 30, 2015 as compared to the same period of 2014, partially offset by higher employee benefit expense.

- Nuclear operating costs increased $20 million as a result of higher employee benefit expense and higher outage costs.

- Transmission expenses decreased $87 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in the first quarter of 2014 of which a portion were passed through to commercial and industrial customers, as discussed above.

Other operating expenses decreased $80 million primarily due to a $46 million decrease in retail-related costs, and a $50 million decrease in mark-to-market expenses on commodity contract positions, partially offset by a $16 million impairment associated with transportation equipment during the second quarter of 2015.

Depreciation expense increased $8 million as a result of a higher asset base from projects such as MATS compliance and the Davis-Besse steam generator replacement completed in May 2014.

General taxes decreased $14 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

Other Expense —

Total other expense increased $28 million in the first six months of 2015, compared to the same period of 2014, primarily due to lower investment income of $30 million primarily on NDT investments and lower capitalized interest of $2 million primarily due to the completion of the Davis-Besse steam generator replacement in May 2014, partially offset by the absence of a $5 million loss on debt redemptions incurred in the first six months of 2014.

Discontinued Operations —

Discontinued operations decreased $116 million in the first six months of 2015 compared to the same period of 2014 primarily due to a pre-tax gain of approximately $177 million associated with the sale of certain hydroelectric facilities on February 12, 2014.

Income Tax Benefits —

FES' effective tax rate from continuing operations for the six months ended June 30, 2015 and 2014 was 20.0% and 39.3%, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pre-tax losses, is primarily due to a reduction in state deferred tax liabilities in 2014 resulting from changes in state apportionment factors as well as an increase in uncertain tax benefits in 2015.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Information" in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

(b) Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2015, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FE's and FES' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Note 9, Regulatory Matters, and Note 10, Commitments, Guarantees and Contingencies, of the Combined Notes to the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

During the quarter ended June 30, 2015, there were no material changes to the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2014.

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

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy		
(A)	12	Fixed charge ratio
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
(A)	99	Description of Common Stock and Preferred Stock
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended June 30, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
FES		
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended June 30, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

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

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy nor FES have filed as an exhibit to this Form 10-Q any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but each hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

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

July 30, 2015

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

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

EXHIBIT INDEX

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