

FIRSTENERGY CORP
Form 10-Q
May 06, 2014

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

FORM 10-Q
(Mark One)

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

For the quarterly period ended March 31, 2014

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 No 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 No 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 FirstEnergy Corp.

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Accelerated Filer N/A

Non-accelerated Filer (Do not check if a smaller reporting company) FirstEnergy Solutions Corp.

Smaller Reporting Company N/A

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

Yes No 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 APRIL 30, 2014
FirstEnergy Corp., \$0.10 par value	419,908,686
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," "will," "intend," "believe," "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 continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.

- The accomplishment of our regulatory and operational goals in connection with our transmission plan and planned distribution rate cases and the effectiveness of our repositioning strategy.

- The impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases.

- 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 the polar vortex or other significant weather events.

- Regulatory outcomes associated with storm restoration, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.

- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on retail margins.

- 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, possible GHG emission, water discharge, water intake and CCR regulations, the potential impacts of CSAPR, and the effects of the EPA's MATS rules including our estimated costs of compliance.

- 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 expenditures 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, among other things, RMR arrangements and the reliability of the transmission grid.

- 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 and the steam generator replacement at Davis-Besse.

- The impact of future changes to the operational status or availability of our generating units.

- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.

- 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 reduce costs and to successfully complete our announced financial plans designed to improve our credit metrics and strengthen our balance sheet, including but not limited to, our announced dividend reduction and our proposed capital raising and debt reduction 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 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 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 our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.

•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 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.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply
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
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 and TrAIL and has a joint venture in PATH.
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a 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
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
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	

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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.
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right

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GLOSSARY OF TERMS, Continued

ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBA	Collective Bargaining Agreement
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
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
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
Dayton	The Dayton Power and Light Company
DCR	Delivery Capital Recovery
DSP	Default Service Plan
Duke	Duke Energy Ohio, a subsidiary of Duke Energy Corporation
EDC	Electric Distribution Company
EDU	Electric Distribution Utility
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
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.
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.
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LOC	Letter of Credit
LSE	Load Serving Entity
MAAC	Mid-Atlantic Region of PJM

MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
mmBTU	One Million British Thermal Units

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GLOSSARY OF TERMS, Continued

Moody's	Moody's Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
NITS	Network Integration Transmission System
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
NOV	Notice of Violation
NO _x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
Pennsylvania Industrials	ME Industrial Users Group and PN Industrial Customer Alliance
PJM	PJM Interconnection LLC
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
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
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 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission

GLOSSARY OF TERMS, Continued

SERTP	Southeastern Regional Transmission Planning
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
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
TMDL	Total Maximum Daily Load
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
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVCAG	West Virginia Citizen Action Group
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)

(In millions, except per share amounts)	Three Months Ended March 31		
	2014	2013	
REVENUES:			
Electric utilities	\$2,739	\$2,388	
Unregulated businesses	1,450	1,335	
Total revenues*	4,189	3,723	
OPERATING EXPENSES:			
Fuel	617	630	
Purchased power	1,455	946	
Other operating expenses	1,182	882	
Provision for depreciation	294	293	
Amortization (deferral) of regulatory assets, net	(28) 59	
General taxes	271	265	
Total operating expenses	3,791	3,075	
OPERATING INCOME	398	648	
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	(7) (117)
Investment income	22	18	
Interest expense	(265) (258)
Capitalized interest	22	15	
Total other expense	(228) (342)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	170	306	
INCOME TAXES	48	114	
INCOME FROM CONTINUING OPERATIONS	122	192	
Discontinued operations (net of income taxes of \$69 and \$2, respectively) (Note 13)	86	4	
NET INCOME	\$208	\$196	
EARNINGS PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	\$0.29	\$0.46	
Basic - Discontinued Operations (Note 13)	0.21	0.01	

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Basic - Net Earnings per Basic Share	\$0.50	\$0.47
Diluted - Continuing Operations	\$0.29	\$0.46
Diluted - Discontinued Operations (Note 13)	0.20	0.01
Diluted - Net Earnings per Diluted Share	\$0.49	\$0.47
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:		
Basic	419	418
Diluted	420	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK**	\$0.72	\$0.55

* Includes excise tax collections of \$117 million and \$122 million in the three months ended March 31, 2014 and 2013, respectively.

** The three months ended March 31, 2014 includes a dividend declared of \$0.36 per share on January 21, 2014, paid on March 1, 2014 and a dividend declared of \$0.36 per share on March 18, 2014, payable June 1, 2014. The three months ended March 31, 2013 includes a dividend declared of \$0.55 per share on March 19, 2013, paid on June 1, 2013.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31	
	2014	2013
NET INCOME	\$208	\$196
OTHER COMPREHENSIVE INCOME (LOSS):		
Pensions and OPEB prior service costs	(42) (46
Amortized losses on derivative hedges	—	1
Change in unrealized gain on available-for-sale securities	21	5
Other comprehensive loss	(21) (40
Income tax benefits on other comprehensive loss	(8) (16
Other comprehensive loss, net of tax	(13) (24
COMPREHENSIVE INCOME	\$195	\$172

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)	March 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 109	\$ 218
Receivables-		
Customers, net of allowance for uncollectible accounts of \$55 in 2014 and \$52 in 2013	1,869	1,720
Other, net of allowance for uncollectible accounts of \$3 in 2014 and 2013	218	198
Materials and supplies, at average cost	740	752
Prepaid taxes	240	226
Derivatives	247	166
Accumulated deferred income taxes	375	366
Collateral	580	155
Other	199	212
	4,577	4,013
PROPERTY, PLANT AND EQUIPMENT:		
In service	44,782	44,228
Less — Accumulated provision for depreciation	13,555	13,280
	31,227	30,948
Construction work in progress	2,661	2,304
	33,888	33,252
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,263	2,201
Other	898	903
	3,161	3,104
ASSETS HELD FOR SALE		
	—	235
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,798	1,854
Other	1,386	1,548
	9,602	9,820
	\$51,228	\$50,424
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 1,416	\$ 1,415
Short-term borrowings	3,085	3,404
Accounts payable	1,455	1,250
Accrued taxes	527	485
Accrued compensation and benefits	232	351
Derivatives	159	111
Other	863	621
	7,737	7,637
CAPITALIZATION:		

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Common stockholders' equity-		
Common stock, \$0.10 par value, authorized 490,000,000 shares - 419,837,287 shares and 418,628,559 shares outstanding as of March 31, 2014 and December 31, 2013, respectively	42	42
Other paid-in capital	9,793	9,776
Accumulated other comprehensive income	271	284
Retained earnings	2,496	2,590
Total common stockholders' equity	12,602	12,692
Noncontrolling interest	3	3
Total equity	12,605	12,695
Long-term debt and other long-term obligations	16,804	15,831
	29,409	28,526
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,028	6,968
Retirement benefits	2,713	2,689
Asset retirement obligations	1,704	1,678
Deferred gain on sale and leaseback transaction	850	858
Adverse power contract liability	255	290
Other	1,532	1,778
	14,082	14,261
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	\$51,228	\$50,424

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	\$208	\$196
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	294	293
Amortization (deferral) of regulatory assets, net	(28)) 59
Nuclear fuel amortization	48	53
Deferred purchased power and other costs	(34)) (25)
Deferred income taxes and investment tax credits, net	181	134
Deferred rents and lease market valuation liability	33	37
Retirement benefits	(20)) (64)
Commodity derivative transactions, net (Note 8)	(17)) 4
Loss on debt redemptions	7	117
Income from discontinued operations (Note 13)	(86)) (4)
Changes in current assets and liabilities-		
Receivables	(168)) (34)
Materials and supplies	12	26
Prepayments and other current assets	(29)) (159)
Accounts payable	200	(378)
Accrued taxes	(242)) (128)
Accrued interest	46	53
Accrued compensation and benefits	(118)) (91)
Cash collateral, net	(461)) (1)
Other	82	(38)
Net cash (used for) provided from operating activities	(92)) 50
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	1,467	1,800
Short-term borrowings, net	—	181
Redemptions and Repayments-		
Long-term debt	(489)) (846)
Short-term borrowings, net	(319)) —
Tender premiums paid on debt redemptions	—	(110)
Common stock dividend payments	(151)) (230)
Other	(10)) (23)
Net cash provided from financing activities	498	772
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(821)) (826)
Nuclear fuel	(55)) (27)
Proceeds from asset sales	394	—
Sales of investment securities held in trusts	621	539

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Purchases of investment securities held in trusts	(646)	(565)
Cash investments	28		6	
Asset removal costs	(39)	(53)
Other	3		(1)
Net cash used for investing activities	(515)	(927)
Net change in cash and cash equivalents	(109)	(105)
Cash and cash equivalents at beginning of period	218		172	
Cash and cash equivalents at end of period	\$109		\$67	

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

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

(In millions)	Three Months Ended March 31		
	2014	2013	
STATEMENTS OF INCOME			
REVENUES:			
Electric sales to non-affiliates	\$ 1,440	\$ 1,334	
Electric sales to affiliates	349	156	
Other	40	34	
Total revenues	1,829	1,524	
OPERATING EXPENSES:			
Fuel	319	300	
Purchased power from affiliates	64	132	
Purchased power from non-affiliates	1,029	506	
Other operating expenses	452	379	
Provision for depreciation	74	75	
General taxes	39	37	
Total operating expenses	1,977	1,429	
OPERATING INCOME (LOSS)	(148) 95	
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	(5) (71)
Investment income	20	17	
Miscellaneous income	—	2	
Interest expense — affiliates	(2) (1)
Interest expense — other	(36) (52)
Capitalized interest	12	9	
Total other expense	(11) (96)
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(159) (1)
INCOME TAX BENEFITS	(56) —	
LOSS FROM CONTINUING OPERATIONS	(103) (1)
Discontinued operations (net of income taxes of \$70 and \$2, respectively) (Note 13)	116	3	
NET INCOME	\$ 13	\$ 2	
STATEMENTS OF COMPREHENSIVE INCOME			
NET INCOME	\$ 13	\$ 2	

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OTHER COMPREHENSIVE INCOME (LOSS):

Pensions and OPEB prior service costs	(5)	(6)
Amortized loss on derivative hedges	(2)	(1)
Change in unrealized gain on available-for-sale securities	19		5	
Other comprehensive income (loss)	12		(2)
Income taxes (benefits) on other comprehensive income (loss)	4		(1)
Other comprehensive income (loss), net of tax	8		(1)
COMPREHENSIVE INCOME	\$21		\$1	

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)	March 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$2	\$2
Receivables-		
Customers, net of allowance for uncollectible accounts of \$13 in 2014 and \$11 in 2013	583	539
Affiliated companies	369	1,036
Other, net of allowance for uncollectible accounts of \$3 in 2014 and 2013	151	81
Notes receivable from affiliated companies	215	—
Materials and supplies	427	448
Derivatives	244	165
Collateral	544	136
Prepayments and other	179	109
	2,714	2,516
PROPERTY, PLANT AND EQUIPMENT:		
In service	12,796	12,472
Less — Accumulated provision for depreciation	4,857	4,755
	7,939	7,717
Construction work in progress	1,356	1,308
	9,295	9,025
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,323	1,276
Other	11	11
	1,334	1,287
ASSETS HELD FOR SALE	—	122
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	91	95
Goodwill	23	23
Property taxes	30	41
Unamortized sale and leaseback costs	197	168
Derivatives	65	53
Other	150	172
	556	552
	\$13,899	\$13,502
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$465	\$892
Short-term borrowings-		
Affiliated companies	—	431
Other	555	4
Accounts payable-		
Affiliated companies	327	765

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Other	295	290
Accrued taxes	97	66
Derivatives	159	110
Other	214	197
	2,112	2,755
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding as of March 31, 2014 and December 31, 2013	3,580	3,080
Accumulated other comprehensive income	62	54
Retained earnings	2,191	2,178
Total common stockholder's equity	5,833	5,312
Long-term debt and other long-term obligations	2,551	2,130
	8,384	7,442
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	850	858
Accumulated deferred income taxes	810	741
Asset retirement obligations	1,029	1,015
Retirement benefits	189	185
Derivatives	36	14
Other	489	492
	3,403	3,305
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	\$13,899	\$13,502

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)	Three Months Ended March	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	\$13	\$2
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	74	75
Nuclear fuel amortization	48	53
Deferred rents and lease market valuation liability	21	21
Deferred income taxes and investment tax credits, net	48	56
Commodity derivative transactions, net (Note 8)	(17) 3
Loss on debt redemptions	5	71
Income from discontinued operations (Note 13)	(116) (3
Changes in current assets and liabilities-		
Receivables	553	(177
Materials and supplies	21	28
Prepayments and other current assets	(48) (55
Accounts payable	(430) (185
Accrued taxes	(49) (80
Accrued compensation and benefits	(19) (16
Cash collateral, net	(420) 38
Other	4	(26
Net cash used for operating activities	(312) (195
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	417	—
Short-term borrowings, net	120	702
Equity contribution from parent	500	—
Redemptions and repayments-		
Long-term debt	(445) (476
Tender premiums paid on debt redemptions	—	(67
Other	(4) (1
Net cash provided from financing activities	588	158
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(298) (217
Nuclear fuel	(55) (27
Proceeds from asset sales	307	17
Sales of investment securities held in trusts	423	252
Purchases of investment securities held in trusts	(438) (265
Loans to affiliated companies, net	(215) 276
Other	—	1
Net cash (used for) provided from investing activities	(276) 37

Net change in cash and cash equivalents	—	—
Cash and cash equivalents at beginning of period	2	3
Cash and cash equivalents at end of period	\$2	\$3

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

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

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

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy'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 and FET. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc.

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, 2013.

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 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.

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with our sale of hydro assets discussed in additional detail in Note 13, Discontinued Operations.

New Accounting Pronouncements

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

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 March	
	31	2013
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2014	2013
Income from continuing operations	\$122	\$192
Discontinued operations (Note 13)	86	4
Net income	\$208	\$196
Weighted average number of basic shares outstanding	419	418
Assumed exercise of dilutive stock options and awards ⁽¹⁾	1	1
Weighted average number of diluted shares outstanding	420	419
Earnings per share:		
Basic earnings per share:		
Income from continuing operations	\$0.29	\$0.46
Discontinued operations (Note 13)	0.21	0.01
Net earnings per basic share	\$0.50	\$0.47
Diluted earnings per share:		
Income from continuing operations	\$0.29	\$0.46
Discontinued operations (Note 13)	0.20	0.01
Net earnings per diluted share	\$0.49	\$0.47

For the three months ended March 31, 2014, 2 million shares were excluded from the calculation of diluted shares⁽¹⁾ outstanding, as their inclusion would be antidilutive. The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect was not significant for the three months ended March 31, 2013.

3. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

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

Components of Net Periodic Benefit Costs (Credits) For the Three Months Ended March 31,	Pensions		OPEB	
	2014	2013	2014	2013
	(In millions)			
Service costs	\$42	\$49	\$2	\$3
Interest costs	100	93	10	9
Expected return on plan assets	(115) (125) (8) (8
Amortization of prior service costs (credits)	2	3	(44) (50
Net periodic costs (credits)	\$29	\$20	\$(40) \$(46

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

For the Three Months Ended March 31,	Pensions		OPEB	
	2014	2013	2014	2013
	(In millions)			
Net Periodic Costs	\$4	\$5	\$(5) \$(5

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

Net Periodic Benefit Expense (Credit) For the Three Months Ended March 31,	Pensions		OPEB	
	2014	2013	2014	2013
	(In millions)			
FirstEnergy	\$21	\$11	\$(27) \$(30
FES	4	3	(4) (3

4. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three months ended March 31, 2014 and 2013, for FirstEnergy and FES 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 January 1, 2014	\$(36) \$9	\$311	\$284
Other comprehensive income before reclassifications	—	22	—	22
Amounts reclassified from AOCI	—	(9) (26) (35
Net other comprehensive income (loss)	—	13	(26) (13
AOCI Balance as of March 31, 2014	\$(36) \$22	\$285	\$271
AOCI Balance as of January 1, 2013	\$(38) \$15	\$408	\$385
Other comprehensive income before reclassifications	—	15	—	15
Amounts reclassified from AOCI	1	(12) (28) (39
Net other comprehensive income (loss)	1	3	(28) (24
AOCI Balance as of March 31, 2013	\$(37) \$18	\$380	\$361

FES

	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, 2014	\$(1) \$8	\$47	\$54
Other comprehensive income before reclassifications	—	21	—	21
Amounts reclassified from AOCI	(1) (9) (3) (13
Net other comprehensive income (loss)	(1) 12	(3) 8
AOCI Balance as of March 31, 2014	\$(2) \$20	\$44	\$62
AOCI Balance as of January 1, 2013	\$3	\$13	\$56	\$72
Other comprehensive income before reclassifications	—	14	—	14

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Amounts reclassified from AOCI	(1) (10) (4) (15)
Net other comprehensive income (loss)	(1) 4	(4) (1)
AOCI Balance as of March 31, 2013	\$2	\$17	\$52	\$71	

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The following amounts were reclassified from AOCI in the three months ended March 31, 2014 and 2013:

FE Reclassifications from AOCI (b)	Three Months Ended March 31		Affected Line Item in Consolidated Statements of Income
	2014	2013	
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	\$ (2) \$ (3) Other operating expenses
			Interest expense (\$2) in 2014 and Interest
Long-term debt	2	4	expense (\$2) and loss on debt redemptions
			(\$2) in 2013
	—	1	Total before taxes
	—	—	Income taxes
	\$—	\$1	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	\$ (14) \$ (19) Investment income
	5	7	Income taxes
	\$ (9) \$ (12) Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	\$ (42) \$ (47) (a)
	16	19	Income taxes
	\$ (26) \$ (28) Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.

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

FES Reclassifications from AOCI (b)	Three Months Ended March 31		Affected Line Item in Consolidated Statements of Income
	2014	2013	
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	\$ (2) \$ (3) Other operating expenses
Long-term debt	—	2	Loss on debt redemptions
	(2) (1) Total before taxes
	1	—	Income tax benefits
	\$ (1) \$ (1) Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	\$ (14) \$ (16) Investment income
	5	6	Income tax benefits
	\$ (9) \$ (10) Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	\$ (5) \$ (5) (a)
	2	1	Income tax benefits
	\$ (3) \$ (4) Net of tax

- (a) These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.
- (b) Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

5. INCOME TAXES

FirstEnergy's and FES's interim effective tax rates reflect the estimated annual effective tax rates for 2014 and 2013, adjusted for tax expense associated with certain discrete items.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Significant judgment is required in determining FirstEnergy's income taxes and in evaluating tax positions taken or expected to be taken on its tax returns. There were no material changes to FirstEnergy's unrecognized income tax benefits during the first three months of 2014 or 2013.

As of March 31, 2014, it is reasonably possible that approximately \$35 million of unrecognized income tax benefits, including interest, 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.

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. During the first three months of 2014 and 2013, there were no material changes to the amount of accrued interest. The net amount of interest accrued as of March 31, 2014 and December 31, 2013 was approximately \$9 million.

FirstEnergy's effective tax rate from continuing operations for the three months ended March 31, 2014 and 2013 was 28.2% and 37.2%, respectively. The decrease in the effective tax rate is primarily due to an increase in AFUDC equity flow through, changes in state apportionment factors and the elimination of certain future tax liabilities associated with basis differences.

FES's effective tax rate from continuing operations for the three months ended March 31, 2014 and 2013 was 35.2% and 24.8%, respectively. The increase in the effective tax rate is primarily related to the impact of permanent tax adjustments on estimated annual pretax earnings from continuing operations.

In April 2014, the Internal Revenue Service completed its examination of FE's 2011 and 2012 federal income tax returns and issued Revenue Agent Reports for these years.

6. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses 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 the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 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 trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly-owned limited liability companies of the Ohio Companies (as described below); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities.

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.

Ohio Securitization

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. Each SPE is a bankruptcy-remote, special purpose limited liability company that is restricted to activities necessary to issue phase-in recovery bonds and perform other functions in connection with the bond issuance. Creditors of FirstEnergy and the Ohio Companies have no recourse to any assets or revenues of the SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility.

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. 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.

Trusts

FirstEnergy's consolidated financial statements include PNBV. 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.

PATH-WV

PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of 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.

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 PATH.

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 20 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 two of these NUG entities, it does not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold variable interests in the remaining two entities; 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 were \$61 million and \$49 million during the three months ended March 31, 2014 and 2013, 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.

In March of 2013, FG acquired the remaining interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately \$221 million. Also during 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for \$23 million and in February 2014, NG purchased additional lessor equity interests for approximately \$94 million.

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 March 31, 2014:

	Maximum Exposure (In millions)	Discounted Lease Payments, net ⁽¹⁾	Net Exposure
FES	\$1,293	\$1,081	\$212
Other FE subsidiaries	716	495	221

⁽¹⁾ The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is \$1.1 billion.

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 RTO 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 RTO 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 March 31, 2014, from those used as of

December 31, 2013. 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 three months ended March 31, 2014. 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	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	\$—	\$1,168	\$—	\$1,168	\$—	\$1,365	\$—	\$1,365
Derivative assets - commodity contracts	11	293	—	304	7	208	—	215
Derivative assets - FTRs	—	—	7	7	—	—	4	4
Derivative assets - NUG contracts ⁽¹⁾	—	—	3	3	—	—	20	20
Equity securities ⁽²⁾	464	—	—	464	317	—	—	317
Foreign government debt securities	—	94	—	94	—	109	—	109
U.S. government debt securities	—	167	—	167	—	165	—	165
U.S. state debt securities	—	237	—	237	—	228	—	228
Other ⁽³⁾	54	379	—	433	187	255	—	442
Total assets	\$529	\$2,338	\$10	\$2,877	\$511	\$2,330	\$24	\$2,865
Liabilities								
Derivative liabilities - commodity contracts	\$(8)	\$(179)	\$—	\$(187)	\$(13)	\$(100)	\$—	\$(113)
Derivative liabilities - FTRs	—	—	(8)	(8)	—	—	(12)	(12)
Derivative liabilities - NUG contracts ⁽¹⁾	—	—	(188)	(188)	—	—	(222)	(222)
Total liabilities	\$(8)	\$(179)	\$(196)	\$(383)	\$(13)	\$(100)	\$(234)	\$(347)
Net assets (liabilities) ⁽⁴⁾	\$521	\$2,159	\$(186)	\$2,494	\$498	\$2,230	\$(210)	\$2,518

(1) NUG contracts are generally 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 \$9 million and \$10 million as of March 31, 2014 and December 31, 2013, 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, LCAPP contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended March 31, 2014 and December 31, 2013:

	NUG Contracts ⁽¹⁾			LCAPP Contracts ⁽¹⁾			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)								
January 1, 2013 Balance	\$36	\$(290)	\$(254)	\$—	\$(144)	\$(144)	\$8	\$(9)	\$(1)
Unrealized gain (loss)	(8)	(17)	(25)	—	(22)	(22)	3	1	4
Purchases	—	—	—	—	—	—	6	(15)	(9)
Terminations ⁽²⁾	—	—	—	—	166	166	—	—	—
Settlements	(8)	85	77	—	—	—	(13)	11	(2)
December 31, 2013 Balance	\$20	\$(222)	\$(202)	\$—	\$—	\$—	\$4	\$(12)	\$(8)
Unrealized gain	—	27	27	—	—	—	6	2	8
Settlements	(17)	7	(10)	—	—	—	(3)	2	(1)
March 31, 2014 Balance	\$3	\$(188)	\$(185)	\$—	\$—	\$—	\$7	\$(8)	\$(1)

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

⁽²⁾ See Note 8, Derivative Instruments

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 March 31, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	\$(1)	Model	RTO auction clearing prices	(\$4.20) to \$7.60	\$0.80	Dollars/MWH
NUG Contracts	\$(185)	Model	Generation Electricity regional prices	600 to 5,422,000 \$47.90 to \$59.00	1,033,000 \$53.50	MWH Dollars/MWH

FES

Recurring Fair Value Measurements	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets (In millions)								
Corporate debt securities	\$—	\$586	\$—	\$586	\$—	\$792	\$—	\$792
Derivative assets - commodity contracts	11	294	—	305	7	208	—	215
Derivative assets - FTRs	—	—	4	4	—	—	3	3
Equity securities ⁽¹⁾	327	—	—	327	207	—	—	207
Foreign government debt securities	—	55	—	55	—	65	—	65
U.S. government debt securities	—	25	—	25	—	27	—	27
U.S. state debt securities	—	3	—	3	—	—	—	—
Other ⁽²⁾	—	319	—	319	—	176	—	176
Total assets	\$338	\$1,282	\$4	\$1,624	\$214	\$1,268	\$3	\$1,485
Liabilities								
Derivative liabilities - commodity contracts	\$(8)	\$(179)	\$—	\$(187)	\$(13)	\$(100)	\$—	\$(113)
Derivative liabilities - FTRs	—	—	(8)	(8)	—	—	(11)	(11)
Total liabilities	\$(8)	\$(179)	\$(8)	\$(195)	\$(13)	\$(100)	\$(11)	\$(124)
Net assets (liabilities) ⁽³⁾	\$330	\$1,103	\$(4)	\$1,429	\$201	\$1,168	\$(8)	\$1,361

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

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

(3) Excludes \$8 million and \$9 million as of March 31, 2014 and December 31, 2013, 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 March 31, 2014 and December 31, 2013:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
(In millions)			
January 1, 2013 Balance	\$6	\$(6)	\$—
Unrealized loss	—	(2)	(2)
Purchases	5	(12)	(7)
Settlements	(8)	9	1
December 31, 2013 Balance	\$3	\$(11)	\$(8)
Unrealized gain	3	1	4
Settlements	(2)	2	—
March 31, 2014 Balance	\$4	\$(8)	\$(4)

Level 3 Quantitative Information

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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 March 31, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	\$(4) Model	RTO auction clearing prices	(\$4.20) to \$7.60	\$0.60	Dollars/MWH

INVESTMENTS

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

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 March 31, 2014 and December 31, 2013:

	March 31, 2014 ⁽¹⁾			December 31, 2013 ⁽²⁾		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	\$1,670	\$44	\$1,714	\$1,881	\$33	\$1,914
FES	698	22	720	918	17	935
Equity securities						
FirstEnergy	\$433	\$31	\$464	\$308	\$9	\$317
FES	308	19	327	207	—	207

⁽¹⁾ Excludes short-term cash investments: FE Consolidated - \$324 million; FES - \$276 million.

⁽²⁾ Excludes short-term cash investments: FE Consolidated - \$204 million; FES - \$135 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 months ended March 31, 2014 and 2013 were as follows:

Three Months Ended

March 31, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	\$621	\$28	\$(16)	\$(2)	\$25
FES	423	19	(5)	(2)	15
March 31, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	\$539	\$24	\$(6)	\$(7)	\$26
FES	252	20	(3)	(7)	13

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 March 31, 2014 and December 31, 2013:

	March 31, 2014			December 31, 2013		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	\$24	\$8	\$32	\$33	\$2	\$35

Investments in employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling \$635 million as of March 31, 2014, and \$636 million as of December 31, 2013, 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:

	March 31, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	\$18,034	\$19,321	\$17,049	\$17,957
FES	2,996	3,098	3,001	3,073

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 and its subsidiaries.

FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of March 31, 2014 and December 31, 2013.

On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by \$1 billion to a total of \$3.5 billion and to increase the individual borrower sublimit for FE by \$1 billion to a total of \$3.5 billion. The FES/AE Supply facility was amended to decrease the lending banks' commitments by \$1 billion to a total of \$1.5 billion. The lending banks' commitments under the FET facility remain at \$1 billion and that facility was amended to increase ATSI's individual borrower sublimit to \$500 million from \$100 million and

TRAIL's individual borrower sublimit to \$400 million from \$200 million. FirstEnergy expensed approximately \$5 million (FES - \$3 million) of unamortized debt expense as a result of the amendments. The amount was included in Loss on Debt Redemptions in the Consolidated Statement of Income in the first quarter of 2014.

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.

During the first quarter of 2014, FG and NG remarketed approximately \$417 million of PCRBs previously held by the companies. Of the total, \$182 million was remarketed with a fixed interest rate of 4% per annum with a mandatory put date of June 3, 2019 and \$235 million was remarketed with a fixed interest rate of 3.75% per annum with a mandatory put date of December 3, 2018.

In addition, in the first quarter of 2014, FG and NG repurchased approximately \$197 million and \$16 million of PCRBs, respectively, which were subject to a mandatory tender. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

On April 1, 2014, PN and ME repurchased approximately \$45 million and \$29 million of PCRBs, respectively, which were subject to a mandatory put on such date. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

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. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. 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. The effective portion of gains and losses on a derivative contract is reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled less than \$1 million and \$2 million as of March 31, 2014 and December 31, 2013, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately \$9 million is expected to be amortized to income

during the next twelve months.

FirstEnergy has used forward starting 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 treated 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. No forward starting swap agreements accounted for as a cash flow hedge were outstanding as of March 31, 2014 or December 31, 2013. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled \$57 million and \$59 million as of March 31, 2014 and December 31, 2013, respectively. Based on current estimates, approximately \$9 million will be amortized to interest expense during the next twelve months.

In connection with certain debt redemptions, FirstEnergy recorded interest expense related to deferred losses on terminated interest rate swaps of approximately \$2 million for the three months ended March 31, 2013.

As of March 31, 2014 and December 31, 2013, no commodity or interest rate derivatives were designated as cash flow hedges.

Refer to Note 4, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the three months ended March 31, 2014 and 2013.

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. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of March 31, 2014 and December 31, 2013, 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 \$41 million and \$44 million as of March 31, 2014 and December 31, 2013, respectively. Based on current estimates, approximately \$11 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately \$3 million and \$6 million during the three months ended March 31, 2014 and 2013, respectively.

As of March 31, 2014 and December 31, 2013, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

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

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy's combustion turbine units. 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 March 31, 2014, FirstEnergy's net asset position under commodity derivative contracts was \$117 million, which related to FES positions. Under these commodity derivative contracts, FES posted \$85 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post \$11 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 March 31, 2014, an adverse change of 10% in commodity prices would decrease net income by approximately \$40 million during the next twelve months.

NUGs

As of March 31, 2014, FirstEnergy's net liability position under NUG contracts was \$185 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.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintained two LCAPP contracts, which were financially settled agreements that allowed eligible

generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. JCP&L expected to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts were considered derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts were subject to regulatory accounting, changes in their fair value did not impact earnings. On October 11, 2013, the U.S. District Court for the District of New Jersey declared that the LCAPP was preempted by the FPA and unconstitutional. On October 22, 2013, the Superior Court of New Jersey Appellate Division dismissed two consolidated appeals which had been taken from the final order of the NJBPU which accepted and adopted the recommendation of the NJBPU's Agent regarding implementation of the LCAPP law. Dismissal of the consolidated appeals, along with pending matters currently on remand to the NJBPU, was without prejudice subject to the parties exercising their appellate rights in the federal courts. The parties filed an appeal with the U.S. Court of Appeals for the Third Circuit and briefing by the parties was completed by March 5, 2014. Consistent with the provisions of the LCAPP contracts, the U.S. District Court's ruling was a termination event. During the fourth quarter of 2013, JCP&L issued termination notices to the counterparties and reversed the derivative liability and corresponding regulatory asset on its Consolidated Balance Sheet.

FTRs

As of March 31, 2014, FirstEnergy's and FES's net liability position under FTRs was \$1 million and \$3 million, respectively, and FES posted \$4 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 ARR allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO 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 the RTO, 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	
	March 31, 2014	December 31, 2013		March 31, 2014	December 31, 2013
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	\$240	\$162	Commodity Contracts	\$(154)	\$(102)
FTRs	7	4	FTRs	(5)	(9)
	247	166		(159)	(111)
			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs	(188)	(222)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Other		
Commodity Contracts	64	53	Commodity Contracts	(33)	(11)
NUGs	3	20	FTRs	(3)	(3)
	67	73		(224)	(236)
Derivative Assets	\$314	\$239	Derivative Liabilities	\$(383)	\$(347)

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:

March 31, 2014	Fair Value (In millions)	Amounts Not Offset in Consolidated Balance Sheet		
		Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
Derivative Assets				
Commodity contracts	\$304	\$(182)) \$(4)) \$118
FTRs	7	(7)) —	—
NUG contracts	3	—	—	3
	\$314	\$(189)) \$(4)) \$121
Derivative Liabilities				
Commodity contracts	\$(187)) \$182	\$2	\$(3)
FTRs	(8)) 7	1	—
NUG contracts	(188)) —	—	(188)
	\$(383)) \$189	\$3	\$(191)

December 31, 2013	Fair Value (In millions)	Amounts Not Offset in Consolidated Balance Sheet		
		Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
Derivative Assets				
Commodity contracts	\$215	\$(106)) \$(9)) \$100
FTRs	4	(4)) —	—
NUG contracts	20	—	—	20
	\$239	\$(110)) \$(9)) \$120
Derivative Liabilities				
Commodity contracts	\$(113)) \$106	\$7	\$—
FTRs	(12)) 4	5	(3)
NUG contracts	(222)) —	—	(222)
	\$(347)) \$110	\$12	\$(225)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of March 31, 2014:

	Purchases (In millions)	Sales	Net	Units
Power Contracts	41	38	3	MWH
FTRs	26	—	26	MWH
NUGs	7	—	7	MWH
Natural Gas	65	8	57	mmBTU

The effect of derivative instruments not in a hedging relationship on the Consolidated Statements of Income during the three months ended March 31, 2014 and 2013, are summarized in the following tables:

	Three Months Ended March 31		
	Commodity Contracts (In millions)	FTRs	Total
2014			
Unrealized Gain Recognized in:			
Other Operating Expense ⁽¹⁾	\$12	\$5	\$17
Realized Gain (Loss) Reclassified to:			
Revenues ⁽²⁾	(\$13) \$52	\$39
Purchased Power Expense ⁽³⁾	436	—	436
Other Operating Expense ⁽⁴⁾	—	(7) (7
Fuel Expense	9	—	9

⁽¹⁾ Includes \$12 million for commodity contracts and \$5 million for FTRs associated with FES.

⁽²⁾ Represents losses on structured financial contracts. Includes (\$13) million for commodity contracts and \$51 million for FTRs associated with FES.

⁽³⁾ Realized losses on financially settled wholesale sales contracts of \$321 million resulting from higher market prices were netted in purchased power. Includes \$436 million for commodity contracts associated with FES.

⁽⁴⁾ Includes (\$7) million for FTRs associated with FES.

2013			
Unrealized Loss Recognized in:			
Other Operating Expense ⁽⁵⁾	(\$5) (\$2) (\$7
Realized Gain (Loss) Reclassified to:			
Revenues ⁽⁶⁾	\$10	\$7	\$17
Purchased Power Expense ⁽⁷⁾	(11) —	(11
Other Operating Expense ⁽⁸⁾	—	(9) (9
Fuel Expense	(1) —	(1

⁽⁵⁾ Includes (\$5) million for commodity contracts and (\$1) million for FTRs associated with FES.

⁽⁶⁾ Includes \$10 million for commodity contracts and \$6 million for FTRs associated with FES.

⁽⁷⁾ Includes (\$11) million for commodity contracts associated with FES.

⁽⁸⁾ Includes (\$8) million for FTRs associated with FES.

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during the three months ended March 31, 2014 and 2013, are summarized in the following tables:

	Three Months Ended March 31			Total
	NUGs	LCAPP ⁽¹⁾	Regulated FTRs	
Derivatives Not in a Hedging Relationship with Regulatory Offset				
(In millions)				
2014				
Unrealized Gain on Derivative Instrument	\$27	\$—	\$4	\$31
Realized Loss on Derivative Instrument	(10) —	(1) (11

2013

Unrealized Gain (Loss) on Derivative Instrument	\$18	\$(2) \$—	\$16
Realized Gain (Loss) on Derivative Instrument	23	—	(1) 22

⁽¹⁾ During the fourth quarter of 2013, all LCAPP contracts were terminated as discussed above.

The following tables provide a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during the three months ended March 31, 2014 and 2013:

26

Derivatives Not in a Hedging Relationship with Regulatory Offset	Three Months Ended March 31			
	NUGs	LCAPP ⁽¹⁾	Regulated FTRs	Total
	(In millions)			
Outstanding net liability as of January 1, 2014	\$(202) \$—	\$—	\$(202)
Additions/Change in value of existing contracts	27	—	4	31
Settled contracts	(10) —	(1) (11)
Outstanding net liability as of March 31, 2014	\$(185) \$—	\$3	\$(182)
Outstanding net liability as of January 1, 2013	\$(254) \$(144) \$—	\$(398)
Additions/Change in value of existing contracts	18	(2) —	16
Settled contracts	23	—	(1) 22
Outstanding net liability as of March 31, 2013	\$(213) \$(146) \$(1) \$(360)

⁽¹⁾ During the fourth quarter of 2013, all LCAPP contracts were terminated as discussed above.

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 NYPS. 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 residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately \$101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved

programs. The 2012-2014 plan is expected to cost approximately \$66 million out of the original \$101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. 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.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to \$25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately \$106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein. PE filed its second annual report on March 27, 2014.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, 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 requires 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 has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, 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 expect to make 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. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by July 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

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, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, 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 September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately \$31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of \$603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately \$112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately \$20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and

several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately \$202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by \$214.9 million while the NJBPU Staff recommended a \$207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014. The matter is pending before the ALJ.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of \$736 million of JCP&L's \$744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory

asset impairment charge of approximately \$8 million (pre-tax) as of December 31, 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement and on March 25, 2014, transmitted a copy of that Order to the Office of Administrative Law so that “actual recovery of the 2011 costs can be determined in relation to the pending base rate case.” Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation 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);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM 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 PJM proceedings. The Ohio Companies also agreed to establish a \$12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for

oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing 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; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- 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 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.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak

demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately \$250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response 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. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

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. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. While briefing has been completed, the matter has not been scheduled for oral argument.

SB221 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 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. 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 and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, 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 \$43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. 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, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the ELPC also filed appeals of the PUCO's order. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on March 6, 2014. On April 15, 2014, the Supreme Court of Ohio stayed the briefing

schedule pending the court's resolution of the Ohio Companies' motion to seal certain confidential portions of the appendix and supplement to their merit brief.

The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations. On April 15, 2014, the Ohio Companies reported that they met all of their annual renewable energy resource requirements for reporting year 2013.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014. The PUCO issued its Order in this matter on March 26, 2014, which included a wide range of issues such as, maintaining SSO service in its current form, requiring corporate separation audits of all EDUs, establishing a market development working group, and ordering changes to the bill format. The Ohio Companies filed their Application for Rehearing on April 25, 2014. The Ohio Companies filed their memorandum contra applications for rehearing of other stakeholders on May 5, 2014.

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.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, 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 descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. The Pennsylvania Companies have reached a settlement with all parties on all issues raised in the case with the exception of the treatment of NITS charges. On May 6, 2014, the ALJ issued a Recommended Decision recommending adoption of the settlement without modification and the denial of several parties' request for non-bypassable treatment of NITS charges. A final order is expected from the PPUC by August 2014.

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 a 29-month period that began in January of 2011. 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. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania 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. On September 30, 2013, the U.S. District Court granted the PPUC's motion to dismiss. 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. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court's decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. Oral argument was held on April 8, 2014, and, at the end of the argument, the Third Circuit directed ME and PN, and the PPUC, each to submit a brief on April 16, 2014 on the question of whether it is possible to waive the preemptive effect of FERC's classification of line loss charges as transmission charges. On April 16, 2014, ME and PN, the PPUC, and the Pennsylvania Industrials each submitted briefs on the Third Circuit's questions.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and

Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between \$1 and \$20 million. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements. On March 20, 2014, the PPUC issued an Order initially determining that ME, PN and Penn achieved the 2011 and 2013 statutory energy efficiency benchmarks. The PPUC also initially determined that WP is not in compliance with the 2011 statutory energy efficiency benchmarks but is in compliance with the 2013 energy efficiency benchmarks. As such, the PPUC, with regards to WP's compliance with the 2011 statutory benchmarks, referred the matter to the PPUC Bureau of Investigation and Enforcement for the initiation of an appropriate proceeding no later than May 30, 2014 to investigate whether WP is in compliance with the 2011 statutory benchmarks and whether WP is subject to statutory penalties. The PPUC also ordered that the initial determination will be deemed final unless any petitions challenging its initial determination are filed within 20 days of the Order. On April 9, 2014, WP filed its petition challenging the PPUC's initial determination arguing, among other things, that the May 2011 target was not mandatory and WP is in compliance because it achieved its May 2013 targets. On April 21, 2014, WP filed an appeal with the Commonwealth Court of Pennsylvania in which it challenged the PPUC's initial finding of a violation of Act 129 on due process grounds. On that same day, the Bureau of Investigation and Enforcement, consistent with the PPUC's March 20, 2014 Order, initiated a proceeding by filing a Complaint against WP in which it alleges that WP violated Act 129 and recommends a penalty in the amount of \$11.4 million. The Pennsylvania Companies have 20 days in which to respond to the Complaint. A prehearing conference is scheduled for May 9, 2014 at which time a procedural schedule for this matter is expected to be established.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities 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. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately \$234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requested deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about \$1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the OCA. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ's decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The OCA took exception to one issue and both parties filed replies to exceptions on December 12, 2013. In its March 6, 2014 Opinion and Order, the PPUC rejected the OCA's exception and many of the ALJ's recommendations, including the recommendation to hire an independent consultant and the disallowance of \$5.1 million of customer information system costs, and affirmed the ALJ's recommendation on the accounting treatment for legacy meter costs. The PPUC also directed the Pennsylvania Companies to file an amendment to the Deployment Plan within thirty days of the Order with sufficient supporting documentation for proper evaluation if the Pennsylvania Companies intend to pursue an accelerated deployment schedule, and the PPUC indicated that it would establish an expedited procedural schedule and rule on the filing within 90 days of the March 6, 2014 Order. The Pennsylvania Companies filed an amended Deployment Plan on March 19, 2014, to which, the OCA filed exceptions arguing that the amended plan failed to: 1) list certain potential cost savings categories that are to be considered by the Pennsylvania Companies; and 2) follow proper procedure. On April 7, 2014, the Pennsylvania Companies filed a reply to OCA's exceptions explaining why they should be rejected. A prehearing conference was held on April 25, 2014, and a procedural schedule was established that is expected to allow the PPUC to issue an order by June 5, 2014.

In the PPUC Order approving the FirstEnergy and AE merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and

to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified. On March 24, 2014, the PPUC issued a letter withdrawing the Proposed Rulemaking.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- \$40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional \$20 million annualized base rate increase effective in January 2011;
- Decrease of \$20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed. The WVPSC issued an order on April 14, 2014 approving the plan, stating rate recovery will be addressed in the base rate case filed on April 30, 2014. In the interim, MP and PE are authorized to defer all costs associated with the plan.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately \$322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Concurrently, MP recognized a regulatory liability of approximately \$23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of \$1.1 billion and MP's assumption of a \$73.5 million pollution control note. The \$1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately \$527 million and a note payable to AE Supply of approximately \$573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. The settlement also required MP and PE to file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the Supreme Court of Appeals of West Virginia. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. The Supreme Court of Appeals of West Virginia held oral arguments on March 5, 2014. On April 23, 2014 the Supreme Court of Appeals of West Virginia delivered an Opinion affirming the WVPSC order approving the Generation Resource Transaction.

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately \$96 million, or 9.3%. The filing also included a surcharge to recover costs of MP's and PE's vegetation management program in the amount

of approximately \$48 million. The proposed total rate increase request, including the cost of the vegetation management program, is approximately \$144 million, or 14%. MP and PE anticipate a decision from the WVPSC in February 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, 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 items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an item to RFC. Moreover, it is clear that the 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 power 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 advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a "paper hearing" and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed a Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated with several other cases before that court for briefing and disposition. Briefing is complete, oral argument was held on April 22, 2014, and a decision is expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC again accepted the hybrid method. Certain parties sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating 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. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC

issued an order regarding the effective date of PJM's separate Order No. 1000 regional transmission planning and cost allocation compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing is complete and oral argument was held on March 20, 2014.

The outcome of these 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. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of 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 that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

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 in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone of the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as \$16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO's efforts to impose these costs on the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. 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. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. Briefing is complete, oral argument was held on December 11, 2013, and a decision is expected in the second quarter of 2014.

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

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 U.S. Court of Appeals for 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, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another 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 filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has 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

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately \$62 million and approximately \$59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. PATH, PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

On March 20, 2014, the settlement judge declared an impasse in efforts to achieve settlement. On March 24, 2014, the Chief ALJ terminated settlement judge procedures and appointed an ALJ to preside over the hearing phase of the case. The hearing is scheduled to commence on November 5, 2014. The issues set for hearing include the prudence of the costs, the base return on

equity and the period of recovery. Depending on the outcome of the hearing, PATH-Allegheny