FIRSTENERGY CORP
Form 10-Q
August 05, 2014

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

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

For the quarterly period ended June 30, 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 þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer þ FirstEnergy Corp.

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

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

CLASS	OUTSTANDING AS OF JULY 31, 2014
FirstEnergy Corp., $0.10 par value	420,344,546
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 successfully implement our revised 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 and the ESP IV.
- 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, and all associated regulatory events or actions.
- 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 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, 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 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.
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- 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 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 and equity method investee of MP.
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities.
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
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 wholly-owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
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	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

GLOSSARY OF TERMS, Continued

ASLB	Atomic Safety and Licensing Board
ASU	Accounting Standards Update
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBA	Collective Bargaining Agreement
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
CSA	Coal Sales Agreement
CTA	Consolidated Tax Adjustment
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CWIP	Construction Work in Progress
Dayton	The Dayton Power and Light Company
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
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
EMAAC	Eastern Mid-Atlantic Area Council
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP	Electric Security Plan
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCL	Hydrochloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.

ICG	International Coal Group Inc.
IRS	Internal Revenue Service
kV	Kilovolt
KWH	Kilowatt-hour

GLOSSARY OF TERMS, Continued

LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LMP	Locational Marginal Price
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.
M/kWh	Mill per Kilowatt-Hour
mmBTU	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator, Inc.
NYPSC	New York State Public Service Commission
OATT	Open Access Transmission Tariff
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
Pennsylvania Industrials	ME Industrial Users Group and PN Industrial Customer Alliance
PJM	PJM Interconnection, L.L.C.
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement

PSD	Prevention of Significant Deterioration
PTC	Price-to-Compare
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act

GLOSSARY OF TERMS, Continued

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
SB310	Senate Bill 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
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
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

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

	Three Months Ended June 30		Six Months Ended June 30	
(In millions, except per share amounts)	2014	2013	2014	2013
REVENUES:				
Electric utilities	$2,256	$2,217	$4,988	$4,602
Unregulated businesses	1,240	1,290	2,690	2,625
Total revenues*	3,496	3,507	7,678	7,227
OPERATING EXPENSES:				
Fuel	550	628	1,167	1,258
Purchased power	1,083	866	2,538	1,812
Other operating expenses	1,021	886	2,203	1,768
Provision for depreciation	302	300	596	593
Amortization (deferral) of regulatory assets, net	20	72	(8)	131
General taxes	228	240	499	505
Impairment of long-lived assets	—	473	—	473
Total operating expenses	3,204	3,465	6,995	6,540
OPERATING INCOME	292	42	683	687
OTHER INCOME (EXPENSE):				
Loss on debt redemptions (Note 7)	(1)	(24)	(8)	(141)
Investment income (loss)	29	(15)	51	3
Interest expense	(262)	(256)	(527)	(514)
Capitalized financing costs	32	23	61	41
Total other expense	(202)	(272)	(423)	(611)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	90	(230)	260	76
INCOME TAXES (BENEFITS)	26	(62)	74	52
INCOME (LOSS) FROM CONTINUING OPERATIONS	64	(168)	186	24
Discontinued operations (net of income taxes of $0, $4, $69 and $6, respectively) (Note 13)	—	4	86	8
NET INCOME (LOSS)	$64	$(164)	$272	$32

EARNINGS (LOSSES) PER SHARE OF COMMON STOCK:				
Basic - Continuing Operations	$0.16	$(0.40)	$0.45	$0.06
Basic - Discontinued Operations (Note 13)	—	0.01	0.20	0.02
Basic - Net Earnings (Loss) per Basic Share	$0.16	$(0.39)	$0.65	$0.08
Diluted - Continuing Operations	$0.15	$(0.40)	$0.45	$0.06
Diluted - Discontinued Operations (Note 13)	—	0.01	0.20	0.02
Diluted - Net Earnings (Loss) per Diluted Share	$0.15	$(0.39)	$0.65	$0.08
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	420	418	419	418
Diluted	421	418	420	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK**	$—	$—	$0.72	$0.55

* Includes excise tax collections of $99 million and $107 million in the three months ended June 30, 2014 and 2013, respectively, and $216 million and $229 million in the six months ended June 30, 2014 and 2013, respectively.

** The six months ended June 30, 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, paid on June 1, 2014. The six months ended June 30, 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 (LOSS)
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In millions)	2014	2013	2014	2013
NET INCOME (LOSS)	$64	$(164)	$272	$32
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(42)	(55)	(84)	(101)
Amortized gains (losses) on derivative hedges	(1)	1	(1)	2
Change in unrealized gain on available-for-sale securities	30	(8)	51	(3)
Other comprehensive loss	(13)	(62)	(34)	(102)
Income tax benefits on other comprehensive loss	(6)	(24)	(14)	(40)
Other comprehensive loss, net of tax	(7)	(38)	(20)	(62)
COMPREHENSIVE INCOME (LOSS)	$57	$(202)	$252	$(30)

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$76	$218
Receivables-		
Customers, net of allowance for uncollectible accounts of $59 in 2014 and $52 in 2013	1,731	1,720
Other, net of allowance for uncollectible accounts of $3 in 2014 and $3 in 2013	231	198
Materials and supplies, at average cost	802	752
Prepaid taxes	246	226
Derivatives	249	166
Accumulated deferred income taxes	377	366
Collateral	266	155
Other	205	212
	4,183	4,013
PROPERTY, PLANT AND EQUIPMENT:		
In service	46,133	44,228
Less — Accumulated provision for depreciation	13,797	13,280
	32,336	30,948
Construction work in progress	2,180	2,304
	34,516	33,252
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,364	2,201
Other	896	903
	3,260	3,104
ASSETS HELD FOR SALE	—	235
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,732	1,854
Other	1,279	1,548
	9,429	9,820
	$51,388	$50,424
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,016	$1,415
Short-term borrowings	2,323	3,404
Accounts payable	1,341	1,250
Accrued taxes	397	485
Accrued compensation and benefits	283	351
Derivatives	201	111
Other	612	621
	6,173	7,637
CAPITALIZATION:		

Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 420,271,254 and 418,628,559 shares outstanding as of June 30, 2014 and December 31, 2013, respectively	42	42
Other paid-in capital	9,817	9,776
Accumulated other comprehensive income	264	284
Retained earnings	2,560	2,590
Total common stockholders' equity	12,683	12,692
Noncontrolling interest	2	3
Total equity	12,685	12,695
Long-term debt and other long-term obligations	18,415	15,831
	31,100	28,526
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,081	6,968
Retirement benefits	2,732	2,689
Asset retirement obligations	1,730	1,678
Deferred gain on sale and leaseback transaction	841	858
Adverse power contract liability	237	290
Other	1,494	1,778
	14,115	14,261
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$51,388	$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)

	Six Months Ended June 30	
(In millions)	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$272	$32
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	596	593
Amortization (deferral) of regulatory assets, net	(8)	131
Nuclear fuel amortization	98	98
Deferred purchased power and other costs	(47)	(39)
Deferred income taxes and investment tax credits, net	159	119
Impairments of long-lived assets	—	473
Investment impairments	3	53
Deferred rents and lease market valuation liability	(79)	(75)
Retirement benefits	(42)	(104)
Commodity derivative transactions, net (Note 8)	40	17
Loss on debt redemptions (Note 7)	8	141
Make-whole premiums paid on debt redemptions	—	(61)
Income from discontinued operations (Note 13)	(86)	(8)
Changes in current assets and liabilities-		
Receivables	(44)	(125)
Materials and supplies	(50)	42
Prepayments and other current assets	(20)	(185)
Accounts payable	103	(312)
Accrued taxes	(159)	(205)
Accrued compensation and benefits	(70)	(34)
Cash collateral, net	(127)	(38)
Other	75	(20)
Net cash provided from operating activities	622	493
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	3,137	2,245
Short-term borrowings, net	—	1,285
Redemptions and Repayments-		
Long-term debt	(925)	(1,968)
Short-term borrowings, net	(1,081)	—
Tender premiums paid on debt redemptions	—	(110)
Common stock dividend payments	(302)	(460)
Other	(24)	(16)
Net cash provided from financing activities	805	976
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,809)	(1,412)
Nuclear fuel	(58)	(50)
Proceeds from asset sales	394	—

Sales of investment securities held in trusts	1,164	1,177
Purchases of investment securities held in trusts	(1,221)	(1,173)
Asset removal costs	(47)	(111)
Other	8	(1)
Net cash used for investing activities	(1,569)	(1,570)
Net change in cash and cash equivalents	(142)	(101)
Cash and cash equivalents at beginning of period	218	172
Cash and cash equivalents at end of period	$76	$71

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

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

	Three Months Ended June 30		Six Months Ended June 30	
(In millions)	2014	2013	2014	2013
STATEMENTS OF OPERATIONS				
REVENUES:				
Electric sales to non-affiliates	$1,234	$1,277	$2,674	$2,611
Electric sales to affiliates	176	140	525	296
Other	42	35	82	69
Total revenues	1,452	1,452	3,281	2,976
OPERATING EXPENSES:				
Fuel	334	332	653	632
Purchased power from affiliates	75	137	139	269
Purchased power from non-affiliates	618	525	1,647	1,031
Other operating expenses	468	387	920	766
Provision for depreciation	79	76	153	151
General taxes	29	34	68	71
Total operating expenses	1,603	1,491	3,580	2,920
OPERATING INCOME (LOSS)	(151)	(39)	(299)	56
OTHER INCOME (EXPENSE):				
Loss on debt redemptions (Note 7)	—	(32)	(5)	(103)
Investment income (loss)	24	(18)	44	(1)
Miscellaneous income	4	6	4	8
Interest expense — affiliates	(2)	(5)	(4)	(6)
Interest expense — other	(37)	(39)	(73)	(91)
Capitalized interest	8	10	20	19
Total other expense	(3)	(78)	(14)	(174)
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(154)	(117)	(313)	(118)
INCOME TAX BENEFITS	(67)	(42)	(123)	(42)
LOSS FROM CONTINUING OPERATIONS	(87)	(75)	$(190)	$(76)
Discontinued operations (net of income taxes of $0, $1, $70 and $3, respectively) (Note 13)	—	4	116	7
NET LOSS	$(87)	$(71)	$(74)	$(69)
STATEMENTS OF COMPREHENSIVE LOSS				

NET LOSS	$(87)	$(71)	$(74)	$(69)
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(5)	(5)	(10)	(11)
Amortized gain on derivative hedges	(3)	(1)	(5)	(2)
Change in unrealized gain on available-for-sale securities	25	(8)	44	(3)
Other comprehensive income (loss)	17	(14)	29	(16)
Income taxes (benefits) on other comprehensive income (loss)	7	(5)	11	(6)
Other comprehensive income (loss), net of tax	10	(9)	18	(10)
COMPREHENSIVE LOSS	$(77)	$(80)	$(56)	$(79)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$2
Receivables-		
Customers, net of allowance for uncollectible accounts of $14 in 2014 and $11 in 2013	534	539
Affiliated companies	475	1,036
Other, net of allowance for uncollectible accounts of $3 in 2014 and 2013	97	81
Notes receivable from affiliated companies	168	—
Materials and supplies	466	448
Derivatives	238	165
Collateral	256	136
Prepayments and other	125	109
	2,361	2,516
PROPERTY, PLANT AND EQUIPMENT:		
In service	13,622	12,472
Less — Accumulated provision for depreciation	4,968	4,755
	8,654	7,717
Construction work in progress	682	1,308
	9,336	9,025
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,379	1,276
Other	11	11
	1,390	1,287
ASSETS HELD FOR SALE	—	122
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	86	95
Goodwill	23	23
Property taxes	19	41
Unamortized sale and leaseback costs	215	168
Derivatives	57	53
Other	112	172
	512	552
	$13,599	$13,502
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$291	$892
Short-term borrowings-		
Affiliated companies	—	431
Other	308	4
Accounts payable-		
Affiliated companies	421	765

Other	259	290
Accrued taxes	98	66
Derivatives	200	110
Other	183	197
	1,760	2,755
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares - 7 shares outstanding as of June 30, 2014 and December 31, 2013	3,583	3,080
Accumulated other comprehensive income	72	54
Retained earnings	2,104	2,178
Total common stockholder's equity	5,759	5,312
Long-term debt and other long-term obligations	2,721	2,130
	8,480	7,442
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	841	858
Accumulated deferred income taxes	746	741
Asset retirement obligations	1,044	1,015
Retirement benefits	193	185
Derivatives	43	14
Other	492	492
	3,359	3,305
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$13,599	$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)	Six Months Ended June 30 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(74)	$(69)
Adjustments to reconcile net loss to net cash from operating activities-		
Provision for depreciation	153	151
Nuclear fuel amortization	98	98
Deferred rents and lease market valuation liability	(76)	(72)
Deferred income taxes and investment tax credits, net	(23)	141
Investment impairments	3	45
Retirement benefits	(2)	(3)
Commodity derivative transactions, net (Note 8)	40	17
Loss on debt redemptions (Note 7)	5	103
Make-whole premiums paid on debt redemptions	—	(31)
Income from discontinued operations (Note 13)	(116)	(7)
Changes in current assets and liabilities-		
Receivables	550	(156)
Materials and supplies	(18)	52
Prepayments and other current assets	5	(40)
Accounts payable	(339)	(91)
Accrued taxes	(57)	(134)
Accrued compensation and benefits	(7)	3
Cash collateral, net	(117)	2
Other	58	(9)
Net cash provided from operating activities	83	—
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	637	—
Equity contribution from parent	500	1,500
Redemptions and repayments-		
Long-term debt	(664)	(1,179)
Short-term borrowings, net	(127)	—
Tender premiums paid on debt redemptions	—	(67)
Other	(10)	(5)
Net cash provided from financing activities	336	249
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(477)	(350)
Nuclear fuel	(57)	(50)
Proceeds from asset sales	307	19
Sales of investment securities held in trusts	707	487
Purchases of investment securities held in trusts	(736)	(515)
Loans to affiliated companies, net	(168)	156

Other	5	3
Net cash used for investing activities	(419)	(250)
Net change in cash and cash equivalents	—	(1)
Cash and cash equivalents at beginning of period	2	3
Cash and cash equivalents at end of period	$2	$2

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

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FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

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

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. 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.

For the three months ended June 30, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) includes $14 million and $4 million, respectively, of allowance for equity funds used during construction and $18 million and $19 million, respectively, of capitalized interest. For the six months ended June 30, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) includes $21 million and $7 million, respectively, of allowance for equity funds used during construction, and $40 million and $34 million, respectively, of capitalized interest.

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 the sale of hydro assets discussed in additional detail in Note 13, Discontinued Operations.

New Accounting Pronouncements

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, ASU No. 2014-09 specifies the accounting for costs to obtain or fulfill a contract with a customer and expands disclosure requirements for revenue recognition. This standard is effective for fiscal years beginning after December 15, 2016, with no early adoption permitted, and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

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 (loss) per share of common stock:

(In millions, except per share amounts)	Three Months Ended June 30		Six Months Ended June 30	
Reconciliation of Basic and Diluted Earnings (Loss) per Share of Common Stock	2014	2013	2014	2013
Income (loss) from continuing operations	$64	$(168)	$186	$24
Discontinued operations (Note 13)	—	4	86	8
Net income (loss)	$64	$(164)	$272	$32
Weighted average number of basic shares outstanding	420	418	419	418
Assumed exercise of dilutive stock options and awards[(1)]	1	—	1	1
Weighted average number of diluted shares outstanding	421	418	420	419
Earnings (loss) per share:				
Basic earnings per share:				
Income (loss) from continuing operations	$0.16	$(0.40)	$0.45	$0.06
Discontinued operations (Note 13)	—	0.01	0.20	0.02
Net earnings (loss) per basic share	$0.16	$(0.39)	$0.65	$0.08
Diluted earnings (loss) per share:				
Income (loss) from continuing operations	$0.15	$(0.40)	$0.45	$0.06
Discontinued operations (Note 13)	—	0.01	0.20	0.02
Net earnings (loss) per diluted share	$0.15	$(0.39)	$0.65	$0.08

(1) For the three months ended June 30, 2014 and June 30, 2013, 1 million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. For the six months ended June 30, 2014, 2 million shares were excluded from the calculation of diluted shares outstanding. 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 six months ended June 30, 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)	Pensions		OPEB	
For the Three Months Ended June 30,	2014	2013	2014	2013
	(In millions)			
Service costs	$41	$49	$2	$3
Interest costs	101	93	10	9
Expected return on plan assets	(115)	(125)	(8)	(8)
Amortization of prior service costs (credits)	2	3	(44)	(58)
Net periodic costs (credits)	$29	$20	$(40)	$(54)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Six Months Ended June 30,	2014	2013	2014	2013
	(In millions)			
Service costs	$83	$98	$4	$6
Interest costs	201	186	20	18
Expected return on plan assets	(230)	(250)	(16)	(16)
Amortization of prior service costs (credits)	4	6	(88)	(107)
Net periodic costs (credits)	$58	$40	$(80)	$(99)

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

	Pensions		OPEB	
	2014	2013	2014	2013
	(In millions)			
For the Three Months Ended June 30,	$4	$5	$(5)	$(5)
For the Six Months Ended June 30,	$8	$10	$(10)	$(10)

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)	Pensions		OPEB	
For the Three Months Ended June 30,	2014	2013	2014	2013
	(In millions)			
FirstEnergy	$21	$14	$(27)	$(34)
FES	4	5	(5)	(5)

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Six Months Ended June 30,	2014	2013	2014	2013
	(In millions)			
FirstEnergy	$42	$25	$(54)	$(64)
FES	8	8	(9)	(8)

4. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and six months ended June 30, 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 April 1, 2014	$(36)	$22	$285	$271
Other comprehensive income before reclassifications	1	31	—	32
Amounts reclassified from AOCI	(1)	(12)	(26)	(39)
Net other comprehensive income (loss)	—	19	(26)	(7)
AOCI Balance as of June 30, 2014	$(36)	$41	$259	$264
AOCI Balance as of April 1, 2013	$(37)	$18	$380	$361
Other comprehensive loss before reclassifications	—	(1)	—	(1)
Amounts reclassified from AOCI	—	(4)	(33)	(37)
Net other comprehensive loss	—	(5)	(33)	(38)
AOCI Balance as of June 30, 2013	$(37)	$13	$347	$323

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of April 1, 2014	$(2)	$20	$44	$62
Other comprehensive income (loss) before reclassifications	(1)	28	—	27
Amounts reclassified from AOCI	(2)	(12)	(3)	(17)
Net other comprehensive income (loss)	(3)	16	(3)	10
AOCI Balance as of June 30, 2014	$(5)	$36	$41	$72
AOCI Balance as of April 1, 2013	$2	$17	$52	$71
Other comprehensive loss before reclassifications	—	(1)	—	(1)
Amounts reclassified from AOCI	(1)	(4)	(3)	(8)
Net other comprehensive loss	(1)	(5)	(3)	(9)

AOCI Balance as of June 30, 2013	$1	$12	$49	$62

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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	1	53	—	54
Amounts reclassified from AOCI	(1)	(21)	(52)	(74)
Net other comprehensive income (loss)	—	32	(52)	(20)
AOCI Balance as of June 30, 2014	$(36)	$41	$259	$264
AOCI Balance as of January 1, 2013	$(38)	$15	$408	$385
Other comprehensive income before reclassifications	—	14	—	14
Amounts reclassified from AOCI	1	(16)	(61)	(76)
Net other comprehensive income (loss)	1	(2)	(61)	(62)
AOCI Balance as of June 30, 2013	$(37)	$13	$347	$323

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 (loss) before reclassifications	(1)	49	—	48
Amounts reclassified from AOCI	(3)	(21)	(6)	(30)
Net other comprehensive income (loss)	(4)	28	(6)	18
AOCI Balance as of June 30, 2014	$(5)	$36	$41	$72
AOCI Balance as of January 1, 2013	$3	$13	$56	$72
Other comprehensive income before reclassifications	—	13	—	13
Amounts reclassified from AOCI	(2)	(14)	(7)	(23)
Net other comprehensive loss	(2)	(1)	(7)	(10)
AOCI Balance as of June 30, 2013	$1	$12	$49	$62

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The following amounts were reclassified from AOCI in the three months ended June 30, 2014 and 2013:

FE Reclassifications from AOCI (b)	Three Months Ended June 30 2014	 2013	Affected Line Item in Consolidated Statements of Income (Loss)
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(3)	$(1)	Other operating expenses
Long-term debt	2	2	Interest expense
	(1)	1	Total before taxes
	—	(1)	Income taxes (benefits)
	$(1)	$—	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(19)	$(6)	Investment income (loss)
	7	2	Income taxes (benefits)
	$(12)	$(4)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(42)	$(55)	(a)
	16	22	Income taxes (benefits)
	$(26)	$(33)	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 (Loss) from AOCI.

FES Reclassifications from AOCI (b)	Three Months Ended June 30 2014	 2013	Affected Line Item in Consolidated Statements of Operations
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(3)	$(1)	Other operating expenses
	1	—	Income tax benefits
	$(2)	$(1)	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(18)	$(6)	Investment income (loss)
	6	2	Income tax benefits
	$(12)	$(4)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(5)	$(5)	(a)
	2	2	Income tax benefits
	$(3)	$(3)	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 Operations from AOCI.
The following amounts were reclassified from AOCI in the six months ended June 30, 2014 and 2013:

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FE	Six Months Ended June 30		Affected Line Item in Consolidated Statements of Income (Loss)
Reclassifications from AOCI (b)	2014	2013	
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(5)	$(4)	Other operating expenses
Long-term debt	4	6	Interest expense
	(1)	2	Total before taxes
	—	(1)	Income taxes (benefits)
	$(1)	$1	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(33)	$(25)	Investment income (loss)
	12	9	Income taxes (benefits)
	$(21)	$(16)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(84)	$(101)	(a)
	32	40	Income taxes (benefits)
	$(52)	$(61)	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 (Loss) from AOCI.

FES	Six Months Ended June 30		Affected Line Item in Consolidated Statements of Operations
Reclassifications from AOCI (b)	2014	2013	
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(5)	$(4)	Other operating expenses
Long-term debt	—	2	Interest expense
	(5)	(2)	Total before taxes
	2	—	Income tax benefits
	$(3)	$(2)	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(32)	$(22)	Investment income (loss)
	11	8	Income tax benefits
	$(21)	$(14)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(10)	$(11)	(a)
	4	4	Income taxes benefits
	$(6)	$(7)	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 Operations from AOCI.

5. INCOME TAXES

FirstEnergy’s and FES’ interim effective tax rates reflect the estimated annual effective tax rates for 2014 and 2013, adjusted for tax expense associated with certain discrete items that may occur in any given period, but are not consistent from period to period.

FirstEnergy’s effective tax rates from continuing operations for the three months ended June 30, 2014 and 2013 were 28.9% and 27.0%, respectively. The 2014 effective tax rate was impacted primarily from a reduction in deferred tax liabilities associated with changes in state apportionment factors. The 2013 effective tax rate was impacted primarily from a valuation allowance against state and local NOL carryforwards that offset the benefit received from pre-tax losses. The effective tax rates from continuing operations for the six months ended June 30, 2014 and 2013 were 28.5% and 68.4%, respectively. The decrease in the effective tax rate is primarily due to an increase in the benefit of AFUDC equity flow through, the elimination of certain future tax liabilities associated with basis differences, and the reduction in state deferred tax liabilities resulting from changes in state apportionment factors. Additionally, as discussed above, the 2013 effective tax rate includes the impact of recording a valuation allowance against state and local net operating loss carryforwards.

FES’ effective tax rates from continuing operations for the three months ended June 30, 2014 and 2013 were 43.5% and 35.9%, respectively, and the effective tax rates for the six months ended June 30, 2014 and 2013 were 39.3% and 35.6%, respectively. For both periods, the increase in the effective tax rate is primarily due to an increase in pre-tax losses from continuing operations in jurisdictions with higher tax rates, a benefit resulting from a reduction in state deferred tax liabilities associated with changes in apportionment factors, partially offset by valuation allowances on local net operating loss carryforwards recognized in 2013.

In April 2014, the IRS completed its examination of FirstEnergy’s 2011 and 2012 federal income tax returns and issued Revenue Agent Reports for those years, which did not result in a material impact to FirstEnergy’s effective tax rate.

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. The change in noncontrolling interest within the Consolidated Balance Sheets during the six months ended June 30, 2014, was primarily due to a distribution to owners.

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 19 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 $40 million and $41 million during the three months ended June 30, 2014 and 2013, respectively, and $102 million and $90 million during the six months ended June 30, 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.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. As of June 30, 2014, FirstEnergy's leasehold interest was 8.11% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2. On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests representing approximately half of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term.

FES, and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions as of June 30, 2014:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
	(In millions)		
FES	$1,212	$1,000	$212
Other FE subsidiaries	701	393	308

[1]The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.0 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.

LCAPP contracts are financially settled agreements that allow 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. LCAPP contracts are recorded at fair value.

During the fourth quarter of 2013, all LCAPP contracts were terminated. See Note 8, Derivative Instruments for additional information.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of June 30, 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 six months ended June 30, 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	June 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,194	$—	$1,194	$—	$1,365	$—	$1,365
Derivative assets - commodity contracts	7	262	—	269	7	208	—	215
Derivative assets - FTRs	—	—	37	37	—	—	4	4
Derivative assets - NUG contracts[1]	—	—	2	2	—	—	20	20
Equity securities[2]	700	—	—	700	317	—	—	317
Foreign government debt securities	—	80	—	80	—	109	—	109
U.S. government debt securities	—	172	—	172	—	165	—	165
U.S. state debt securities	—	242	—	242	—	228	—	228
Other[3]	95	272	—	367	187	255	—	442
Total assets	$802	$2,222	$39	$3,063	$511	$2,330	$24	$2,865
Liabilities								
Derivative liabilities - commodity contracts	$(16)	$(212)	$—	$(228)	$(13)	$(100)	$—	$(113)
Derivative liabilities - FTRs	—	—	(16)	(16)	—	—	(12)	(12)
Derivative liabilities - NUG contracts[1]	—	—	(171)	(171)	—	—	(222)	(222)
Total liabilities	$(16)	$(212)	$(187)	$(415)	$(13)	$(100)	$(234)	$(347)
Net assets (liabilities)[4]	$786	$2,010	$(148)	$2,648	$498	$2,230	$(210)	$2,518

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

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

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

(4) Excludes $(36) million and $10 million as of June 30, 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 June 30, 2014 and December 31, 2013:

	NUG Contracts[1]			LCAPP Contracts			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	1	26	27	—	—	—	19	6	25
Purchases	—	—	—	—	—	—	26	(17)	9
Settlements	(19)	25	6	—	—	—	(12)	7	(5)
June 30, 2014 Balance	$2	$(171)	$(169)	$—	$—	$—	$37	$(16)	$21

(1) Changes in the fair value of NUG 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 June 30, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$21	Model	RTO auction clearing prices	($6.70) to $8.00	$1.10	Dollars/MWH
NUG Contracts	$(169)	Model	Generation	600 to 5,202,000	955,000	MWH
			Electricity regional prices	$49.30 to $59.00	$54.10	Dollars/MWH

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FES

Recurring Fair Value Measurements	June 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$651	$—	$651	$—	$792	$—	$792
Derivative assets - commodity contracts	7	262	—	269	7	208	—	215
Derivative assets - FTRs	—	—	26	26	—	—	3	3
Equity securities[(1)]	459	—	—	459	207	—	—	207
Foreign government debt securities	—	57	—	57	—	65	—	65
U.S. government debt securities	—	30	—	30	—	27	—	27
U.S. state debt securities	—	9	—	9	—	—	—	—
Other[(2)]	—	198	—	198	—	176	—	176
Total assets	$466	$1,207	$26	$1,699	$214	$1,268	$3	$1,485
Liabilities								
Derivative liabilities - commodity contracts	$(15)	$(212)	$—	$(227)	$(13)	$(100)	$—	$(113)
Derivative liabilities - FTRs	—	—	(16)	(16)	—	—	(11)	(11)
Total liabilities	$(15)	$(212)	$(16)	$(243)	$(13)	$(100)	$(11)	$(124)
Net assets (liabilities)[(3)]	$451	$995	$10	$1,456	$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 $(25) million and $9 million as of June 30, 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 June 30, 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	15	5	20
Purchases	15	(17)	(2)
Settlements	(7)	7	—
June 30, 2014 Balance	$26	$(16)	$10

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended June 30, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$10	Model	RTO auction clearing prices	($6.70) to $8.00	$0.90	Dollars/MWH

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INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities, 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 June 30, 2014 and December 31, 2013:

	June 30, 2014[1]			December 31, 2013[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,715	$51	$1,766	$1,881	$33	$1,914
FES	805	24	829	918	17	935
Equity securities						
FirstEnergy	$617	$83	$700	$308	$9	$317
FES	411	48	459	207	—	207

(1) Excludes short-term cash investments: FE Consolidated - $139 million; FES - $91 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 and six months ended June 30, 2014 and 2013 were as follows:

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

June 30, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$638	$16	$(11)	$(46)	$22
FES	235	13	(8)	(38)	15

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

June 30, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,177	$40	$(16)	$(53)	$48
FES	487	33	(11)	(45)	28

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of June 30, 2014 and December 31, 2013:

	June 30, 2014			December 31, 2013		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$19	$8	$27	$33	$2	$35

Investments in employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $636 million as of June 30, 2014 and 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:

	June 30, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$19,258	$20,816	$17,049	$17,957
FES	2,993	3,136	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 June 30, 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, included in Loss on Debt Redemptions in the Consolidated Statement of Income (Loss) in the first six months 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. The proceeds from this term loan reduced borrowings under the FE Facility.

During the first quarter of 2014, FG and NG remarketed approximately $235 million and $182 million, respectively, of PCRBs, previously held by the companies. The NG PCRBs were remarketed with a fixed interest rate of 4% per annum and a mandatory put date of June 3, 2019 and the FG PCRBs were remarketed with a fixed interest rate of 3.75% per annum and 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, respectively, of PCRBs, which were subject to a mandatory tender. The PCRBs are being held either for remarketing subject to future market and other conditions or have been remarketed in the second quarter as described below. Additionally, FG retired $50 million of PCRB's at maturity.

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 PCRBs for remarketing subject to future market and other conditions. Additionally, on April 1, 2014, ME retired $150 million of long-term debt at maturity.

On May 19, 2014, FET issued $600 million of 4.35% senior notes due 2025 and $400 million of 5.45% senior notes due 2044. Proceeds received from the issuance of the senior notes were used to (i) repay borrowings under its revolving credit facility and the FirstEnergy unregulated company money pool; (ii) fund a capital contribution to ATSI; and (iii) for working capital needs and other general business purposes.

On June 11, 2014, ME and PN issued $250 million of 4% senior notes due 2025 and $200 million of 4.15% senior notes due 2025, respectively. Proceeds received from the issuance of the senior notes were used to repay ME and PN's borrowings under the FirstEnergy revolving credit facility and the FirstEnergy regulated utility money pool.

In addition, in the second quarter of 2014, FG and NG remarketed approximately $57 million and $164 million, respectively, of PCRBs previously held by the companies. The bonds were remarketed with a fixed interest rate of 3.50% per annum with a mandatory put date of June 1, 2020.

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 (losses) included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled $(3) million and $2 million as of June 30, 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 $7 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 June 30, 2014 or December 31, 2013. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $54 million and $59 million as of June 30, 2014 and December 31, 2013, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months.

As of June 30, 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 and six months ended June 30, 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 June 30, 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 $38 million and $44 million as of June 30, 2014 and December 31, 2013, respectively. Based on current estimates, approximately $12 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 $5 million during the three months ended June 30, 2014 and 2013, respectively, and $6 million and $11 million during the six months ended June 30, 2014 and 2013, respectively.

As of June 30, 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 June 30, 2014, FirstEnergy’s net asset position under commodity derivative contracts was $41 million, which related to FES positions. Under these commodity derivative contracts, FES posted $62 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $41 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of June 30, 2014, an adverse change of 10% in commodity prices would decrease net income by approximately $24 million during the next twelve months.

Interest Rate Swaps

During the three months ended June 30, 2014, FE executed notional $500 million of forward-starting, pay-fixed/receive-float, interest rate swaps with an effective date of December 31, 2015 and a weighted average 10-year fixed rate of 3.21%. On June 10, 2014, the interest rate swaps were terminated resulting in a realized gain and cash proceeds of approximately $6 million. The realized gain is recorded as a reduction to interest expense in the Consolidated Statements of Income (Loss).

NUGs

As of June 30, 2014, FirstEnergy's net liability position under NUG contracts was $169 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 June 30, 2014, FirstEnergy's and FES's net asset position under FTRs was $21 million and $10 million, respectively, and FES posted $5 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of 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 June 30, 2014	December 31, 2013	Derivative Liabilities	Fair Value June 30, 2014	December 31, 2013
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$213	$162	Commodity Contracts	$(186)	$(102)
FTRs	36	4	FTRs	(15)	(9)
	249	166		(201)	(111)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs	(171)	(222)
Commodity Contracts	56	53	Noncurrent Liabilities - Other		
FTRs	1	—	Commodity Contracts	(42)	(11)
NUGs	2	20	FTRs	(1)	(3)
	59	73		(214)	(236)
Derivative Assets	$308	$239	Derivative Liabilities	$(415)	$(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:

		Amounts Not Offset in Consolidated Balance Sheet		
June 30, 2014	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$269	$(183)	$—	$86
FTRs	37	(16)	—	21
NUG contracts	2	(1)	—	1
	$308	$(200)	$—	$108
Derivative Liabilities				
Commodity contracts	$(228)	$183	$13	$(32)

FTRs	(16)	16	—	—
NUG contracts	(171)	1	—	(170)
	$(415)	$200	$13	$(202)

December 31, 2013	Fair Value	Amounts Not Offset in Consolidated Balance Sheet Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
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 June 30, 2014:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	33	35	(2)	MWH
FTRs	82	—	82	MWH
NUGs	7	—	7	MWH
Natural Gas	60	3	57	mmBTU

The effect of derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income (Loss) during the three months ended June 30, 2014 and 2013, are summarized in the following tables:

	Three Months Ended June 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense [1]	$(70)	$13	$—	$(57)
Realized Gain (Loss) Reclassified to:				
Revenues [2]	$2	$(1)	$—	$1
Purchased Power Expense [3]	22	—	—	22
Other Operating Expense [4]	—	(10)	—	(10)
Fuel Expense	2	—	—	2
Interest Expense	—	—	6	6

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

	Three Months Ended June 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2013				
Unrealized Loss Recognized in:				
Other Operating Expense [5]	$(10)	$(1)	$—	$(11)
Realized Gain (Loss) Reclassified to:				
Revenues [6]	$6	$5	$—	$11
Purchased Power Expense [7]	(2)	—	—	(2)
Other Operating Expense [8]	—	(9)	—	(9)
Fuel Expense	2	—	—	2

(5) Includes ($10) million for commodity contracts and ($1) million for FTRs associated with FES.
(6) Includes $5 million for commodity contracts and $5 million for FTRs associated with FES.
(7) Includes ($2) million for commodity contracts associated with FES.
(8) Includes ($8) million for FTRs associated with FES.

	Six Months Ended June 30 Commodity Contracts (In millions)	FTRs	Interest Rate Swaps	Total
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[1]	$(58)	$18	$—	$(40)
Realized Gain (Loss) Reclassified to:				
Revenues[2]	$(11)	$51	$—	$40
Purchased Power Expense[3]	458	—	—	458
Other Operating Expense[4]	—	(17)	—	(17)
Fuel Expense	11	—	—	11
Interest Expense	—	—	6	6

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

	Six Months Ended June 30 Commodity Contracts (In millions)	FTRs	Interest Rate Swaps	Total
2013				
Unrealized Loss Recognized in:				
Other Operating Expense[5]	$(15)	$(2)	$—	$(17)
Realized Gain (Loss) Reclassified to:				
Revenues[6]	$16	$12	$—	$28
Purchased Power Expense[7]	(13)	—	—	(13)
Other Operating Expense[8]	—	(18)	—	(18)
Fuel Expense	2	—	—	2

[5] Includes ($15) million for commodity contracts and ($2) million for FTRs associated with FES.
[6] Includes $15 million for commodity contracts and $11 million for FTRs associated with FES.
[7] Includes ($13) million for commodity contracts associated with FES.
[8] Includes ($16) 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 and six months ended June 30, 2014 and 2013, are summarized in the following tables:

	Three Months Ended June 30			
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
2014				
Unrealized Gain (Loss) on Derivative Instrument	$(2)	$—	$11	$9
Realized Gain (Loss) on Derivative Instrument	18	—	(4)	14
2013				
Unrealized Loss on Derivative Instrument	$(38)	$(12)	$—	$(50)
Realized Gain on Derivative Instrument	20	—	1	21

	Six Months Ended June 30			
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
2014				
Unrealized Gain on Derivative Instrument	$25	$—	$15	$40
Realized Gain (Loss) on Derivative Instrument	8	—	(5)	3
2013				
Unrealized Loss on Derivative Instrument	$(20)	$(14)	$—	$(34)
Realized Gain on Derivative Instrument	43	—	—	43

(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 and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30			
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
Outstanding net liability as of April 1, 2014	$(185)	$—	$3	$(182)
Additions/Change in value of existing contracts	(2)	—	11	9
Settled contracts	18	—	(4)	14
Outstanding net liability as of June 30, 2014	$(169)	$—	$10	$(159)
Outstanding net liability as of April 1, 2013	$(213)	$(146)	$(1)	$(360)
Additions/Change in value of existing contracts	(38)	(12)	—	(50)
Settled contracts	20	—	1	21
Outstanding net liability as of June 30, 2013	$(231)	$(158)	$—	$(389)

	Six Months Ended June 30			
Derivatives Not in a Hedging Relationship with Regulatory Offset	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	25	—	15	40
Settled contracts	8	—	(5)	3
Outstanding net liability as of June 30, 2014	$(169)	$—	$10	$(159)
Outstanding net liability as of January 1, 2013	$(254)	$(144)	$—	$(398)
Additions/Change in value of existing contracts	(20)	(14)	—	(34)
Settled contracts	43	—	—	43
Outstanding net liability as of June 30, 2013	$(231)	$(158)	$—	$(389)

[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 NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

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

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to 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 adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. 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. The MDPSC held a hearing on the utility reports on July 10, 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. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff. In addition, the Staff proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC has scheduled a hearing for September 15-18, 2014, to consider certain of these matters.

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.

In a 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 record in the case was closed as of June 30, 2014, and the matter is pending before the ALJ. On July 24, 2014, Rate Counsel filed a motion with the NJBPU requesting that effective August 1, 2014, JCP&L's existing rates be continued on a provisional basis until the NJBPU's final order in the base rate case and subject to refund. JCP&L filed a brief opposing the motion on August 4, 2014.

On January 23, 2013, the NJBPU opened a generic proceeding to review its policies with respect to the use of a CTA in base rate cases. The NJBPU and its Staff solicited, and were provided, input from interested stakeholders, including utilities and the Rate Counsel. On June 18, 2014, the NJBPU Staff proposed to amend current CTA policy by: 1) calculating savings using a 5 year look back from the beginning of the test year; 2) allocating savings with 75% retained by the company and 25% allocated to rate payers; and 3) excluding transmission assets of electric distribution companies in the savings calculation. Written comments on the Staff proposal are due August 18, 2014.

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) in the fourth quarter of 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. As of June 6, 2014, JCP&L has completed the required compliance filings and continues to implement the required measures directed by the above NJBPU's orders.

OHIO

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the

longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings;

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal 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.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled "Powering Ohio's Progress". The Ohio Companies have requested a decision by the PUCO by April 8, 2015. The material terms of the proposed plan include:

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

Under R.C. 4928.66 (codification of SB221), the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,200 GWHs in 2012 (an increase of 408,000 MWHs over 2011 levels), 1,705 GWHs in 2013, and 2,237 GWHs in 2014, 2015, and 2016, if an amended plan is filed as contemplated by SB310. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2014, and retain the 2014 level for 2015 and 2016 if an amended plan is filed as contemplated by SB310, and then increase the benchmark by an additional 0.75% thereafter through 2020. 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. On May 15, 2014, the Ohio Companies filed their 2013 Annual Portfolio Status Report in which they indicated compliance with 2013 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. 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.

R.C. 4928.64 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. On May 6, 2014, the PUCO issued an Entry extending the confidential treatment to February 13, 2015, of all materials and information previously granted confidential treatment.

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. The PUCO issued its Entry on Rehearing on May 21, 2014, to, among other things: 1) calculate the price to compare based on the current month's charges; and 2) allow EDUs to file for deferral authority when changing bill format.

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 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. On July 24, 2014, the PPUC unanimously approved the settlement, but voted to deny the proposal to recover NITS on a non-bypassable basis.

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 2013 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 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 recommended a penalty in the amount of $11.4 million. A prehearing conference was held on May 9, 2014 at which time the party requested, and the ALJ agreed, to stay the PPUC proceedings while the parties attempt to settle the matter. On July 30, 2014, a Joint Petition for settlement was filed, which would resolve all issues in the pending proceedings, and includes WP making a payment of $1.3 million. The settlement is subject to review and approval of the PPUC. WP's brief in the Commonwealth Court appeal proceeding is due on September 15, 2014.

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 saving 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. On June 25, 2014, the PPUC entered its Opinion and Order to approve the revised plan. The Pennsylvania Companies commenced the implementation phase of the deployment plan in July 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.

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings request approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. The filings also propose several new cost recovery riders as well as revisions to certain existing cost recovery riders. An order on the proposed increases is expected in April 2015.

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.

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%, based on an historic 2013 test year. 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. On June 13, 2014, MP and PE amended their filing to add an additional $7.5 million of additional revenues to reimburse their expected costs of implementing monthly meter reading for residential and small commercial customers. The proposed total rate increase request, including the cost of the vegetation management program and monthly meter reading, is approximately $152 million, or 14.7%. 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. On June 25, 2014, the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from the new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines by means of a postage-stamp rate. The court also found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from them, and not based on load ratio share in PJM as a whole. The court again remanded the case back to FERC for further proceedings to implement its findings and ruling.

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. 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 the SERTP region participants' 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. On May 15, 2014, FERC issued an order denying rehearing of its March 22, 2013 order and accepting in part revisions to the PJM Operating Agreement and OATT proposed by PJM and the

PJM Transmission Owners, including FirstEnergy. FERC also directed PJM and the PJM Transmission Owners to submit a further compliance filing by July 15, 2014. On May 27, 2014, FirstEnergy filed a petition for review of FERC's March 22, 2013 and May 15, 2014 orders with the U.S. Court of Appeals for the D.C. Circuit. The appeal is being held in abeyance pending the resolution of certain other appeals. Other parties' requests for rehearing of certain aspects of the May 15, 2014 order, other appeals of the March 22, 2013 and May 15, 2014 orders, and PJM's and the PJM Transmission Owners' compliance filings pursuant to the May 15, 2014 order are pending.

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 approved before ATSI joined 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. On July 18, 2014, the court denied ATSI’s petition for review, finding that FERC properly determined that the ATSI zone is responsible for an allocation of the “legacy RTEP” project costs and affirming FERC’s orders. However, the amount to be paid is pending before FERC as a result of the June 25, 2014 order from the U.S. Court of Appeals for the Seventh Circuit that is described above in the PJM Transmission Rates section. Specifically, the Seventh Circuit found that eastern PJM utilities are the primary beneficiaries of certain

RTEP projects, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from them, and not based on load ratio share in PJM as a whole. The Seventh Circuit remanded the case back to FERC for further proceedings to develop a cost-allocation methodology consistent with its findings and ruling.

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 January 13, 2015. 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 and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the "joint and common market" stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June 2010, FES and AE Supply have lost more than $94 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply re-filed their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FESC, on behalf of FES and AE Supply, filed a request for rehearing of FERC's order. That request for rehearing, and all subsequent filings in the docket, are pending before FERC. The PJM stakeholders have recently begun discussing the problem of FTR underfunding again.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into four categories: (i) DR; (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. The purpose of PJM’s tariff amendments is to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. In each of the relevant dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC largely approved the tariff amendments as proposed by PJM regarding DR, imports, and transmission upgrade modeling. Compliance filings pursuant to and requests for rehearing of certain of these orders are pending before FERC. On May 9, 2014, FERC rejected the arbitrage/capacity replacement tariff amendments and ordered a technical conference to further examine the issues. The technical conference has not yet been scheduled and requests for rehearing of the May 9, 2014 order are pending before FERC.

PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM RPM capacity tariff describes the rules for calculating the “offer cap” for each unit that offers into the RPM auctions. In summary, the offer cap is calculated by identifying certain going-forward costs, including the going-forward capital requirements, for a given unit, and then subtracting the projected energy and ancillary services revenues, net of marginal costs, from the going-forward costs. The remainder becomes the offer cap. FES learned that the PJM Market Monitor’s practice for calculating the forecast energy and ancillary services revenues has been to use the lower of the unit’s economic or cost-based offers into the PJM energy market. The Market Monitor engages in this practice based on his interpretation of certain provisions of the PJM capacity tariff. However, review of the relevant tariff language suggests that only the cost-based offer data should be used. FES determined that the Market Monitor’s use of the lower of cost-based or economic offer data has the effect of suppressing the offer cap, which can distort the price signal that is intended to come out of the RPM auction process. On April 7, 2014, FES submitted a Petition for Declaratory Order to FERC, asking for an interpretation of the relevant provisions of the PJM capacity tariff. Specifically, FES identified the difference of opinion between FES and PJM and the Market Monitor regarding interpretation of the relevant provision. FES asked FERC to rule on the question of whether the tariff language permits the Market Monitor's use of the lower of cost-based or economic offer data or requires use of the cost-based offer data by May 9, 2014. On April 18, 2014, the Market Monitor and other parties filed protests to FES's petition, arguing that the PJM capacity tariff allows the Market Monitor to use market-based energy offers instead of cost-based energy offers in calculating RPM auction offer caps and asking FERC to delay action on the petition until after the May 2014 BRA. FES' petition, the protest, and related filings are pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

PJM RPM Auctions - Complaint Regarding 2014 PJM BRA

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP, just as if DR were a traditional energy resource. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC therefore lacked jurisdiction to regulate DR, such as via the

PJM tariffs and programs. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was receiving a double payment (LMP plus the savings of foregone energy purchases). On July 7, 2014, FERC and other parties requested that the U.S. Court of Appeals for the D.C. Circuit grant rehearing en banc, which is a procedural path to ask the full U.S. Court of Appeals for the D.C. Circuit to reconsider the panel's decision. On July 11, 2014, FERC clarified that it is petitioning for rehearing en banc solely regarding the issue of jurisdiction, and not any other issue, including compensation and cost allocation. On August 4, 2014, and acting pursuant to a court order, the original trade group petitioners and Old Dominion Electric Cooperative filed a joint response to FERC's petition for rehearing en banc. On May 23, 2014, FESC, on behalf of FE entities with market-based rate authority, filed a complaint asking FERC to direct PJM to remove all portions of the PJM OATT, which allows or requires PJM to include DR in the PJM capacity market, and to invalidate the results of the May 2014 RPM capacity auction on the grounds that the U.S. Court of Appeals for the D.C. Circuit’s May 23, 2014 decision required removal of DR from the wholesale capacity markets. In a subsequent pleading, FESC stated its intent to file an amended complaint. FESC expects to file the amended complaint in late summer 2014. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

10. COMMITMENTS, GUARANTEES AND CONTINGENCIES

GUARANTEES AND OTHER ASSURANCES

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

As of June 30, 2014, outstanding guarantees and other assurances aggregated approximately $4.0 billion, consisting of parental guarantees ($717 million), subsidiaries' guarantees ($2,460 million) and other guarantees ($855 million).

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

COLLATERAL AND CONTINGENT-RELATED FEATURES

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

Bilateral agreements and derivative instruments entered into by FirstEnergy and its subsidiaries have margining provisions that require posting of collateral. Based on the Competitive Energy Segments power portfolio exposures as of June 30, 2014, FES has posted collateral of $274 million and AE Supply has posted collateral of $4 million. The Regulated Distribution segment has posted collateral of $6 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations as of June 30, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$517	$6	$53	$576
BB+/Ba1 Credit Ratings	$560	$6	$53	$619
Full impact of credit contingent contractual obligations	$825	$71	$89	$985

Excluded from the preceding chart is the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of June 30, 2014, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $105 million.

OTHER COMMITMENTS AND CONTINGENCIES

FE is a guarantor under a syndicated three-year senior secured term loan facility dated October 18, 2011, as amended, that matures October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guarantees of the obligations of Global Holding under the new facility.

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

FE, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed, most recently as of August 14, 2013, to use their best efforts to refinance the facility no later than July 20, 2015, on a non-recourse basis so that FE's guaranty can be terminated and/or released. If that refinancing does not occur, FE may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the facility in full. In lieu of providing such funding, the co-owners, at FE's option, may provide their several guaranties of Global Holding's obligations under the facility. Since January 1, 2013, FE has received a fee for providing its guaranty. The fee is payable semiannually, and accrues at a rate of 5% per annum on the average daily outstanding aggregate commitments under the facility for each semiannual period.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

CAA Compliance

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

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the

Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that AE performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, MP, PE and WP finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. On March 10, 2014, New York, Connecticut, and Maryland filed an appeal with the U.S. Court of Appeals for the Third Circuit. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to “temporarily preserve its environmental values” until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On April 29, 2014 the U.S. Supreme Court reversed the D.C Circuit decision vacating CSAPR and generally upheld the EPA's authority under the CAA to establish the regulatory structure underpinning CSAPR. Depending on the outcome of further proceedings in this matter and how the EPA and the states implement the final rules, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS was challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. On April 15, 2014, MATS was upheld by the U.S. Court of Appeals for the D.C. Circuit, however, the Court refused to decide FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers due to a January 2013 petition for reconsideration still pending but not addressed by EPA. On July 14, 2014, various entities filed a petition seeking further review by the U.S. Supreme Court. Depending on the outcome of further appeals, if any, and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $370 million (Competitive Energy Services segment of $178 million and Regulated Distribution segment of $192 million), reduced from the previous estimate of $465 million.

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. FG intends to operate the plants through April 2015, subject to market conditions. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have agreed to pay liquidated damages for delivery shortfalls for 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FE and FES are unable to estimate the loss or range of loss.

On July 1, 2014, FES terminated a long-term fuel supply agreement. In connection with this termination, FES recognized a pre-tax charge of $67 million in the second quarter of 2014.

Climate Change

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

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as "air pollutants" under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel electric generating units. On September 20, 2013, the EPA proposed a new source performance standard, which would not apply to any existing, modified, or reconstructed fossil fuel generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. On June 2, 2014, the EPA proposed regulations to reduce CO_2 emissions from existing fossil fuel electric generating units that would require each state to develop implementation plans by June 30, 2016, to meet EPA's state specific emission rate goals. EPA's proposal allows states to request a 1-year extension for single-state implementation plans (June 30, 2017) or a 2-year extension for multi-state implementation plans (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel electric generating units. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 U.S. Court of Appeals for the D.C. Circuit decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other greenhouse gas emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by EPA to install greenhouse gas control technologies. Depending on how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. In 1997, the U.S. Senate passed the Byrd-Hagel resolution by a unanimous vote of 95-0. The resolution stated that it is the sense of the Senate that the United States should not be a signatory to any protocol to, or other agreement regarding, the United Nations Framework Convention on Climate Change which would mandate new commitments to limit or reduce GHG emissions, unless the protocol or other agreement also mandates new specific scheduled commitments to limit or reduce GHG emissions for developing country parties within the same compliance period, or would not result in serious harm to the economy of the United States. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective. In November 2013, the U.N. Climate Change Conference in Warsaw, Poland advanced negotiations of a new global agreement to reduce GHG emissions by 2015. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

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

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. On May 19, 2014, the EPA finalized Section 316(b) regulations requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies by cooling water intake structures exceeding 125 million gallons per day. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's cooling water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

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

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013. On April 21, 2014, PA DEP recommended that the sulfate impairment designation for the Monongahela River be removed in its bi-annual water report. A 45-day public comment period ended on June 10, 2014, and PA DEP must obtain EPA approval to remove the sulfate impairment designation which would eliminate the need to develop a TMDL.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of CCRs produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of CCRs, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of CCRs. On April 19, 2013, the EPA stated it would "align" its proposed CCR regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the potential enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its ARO for LBR by $163 million in 2013. On April 3, 2014, PA DEP issued a permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizes FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCBs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, against the owner and operator of that mine, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site.

Lawsuits initially filed on October 10, 2013 and December 5, 2013, are pending against FG involving approximately 61 individuals in the U.S. District Court for the Northern District of West Virginia and approximately 26 individuals (16 of which have settled their claims) in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the

Impoundment. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in the complaints, but, at this time, is unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any CCR regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of June 30, 2014 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $130 million have been accrued through June 30, 2014. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of June 30, 2014, FirstEnergy had approximately $2.4 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. By a letter dated July 2, 2014, FENOC submitted a $155 million FES parental guaranty relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry to the NRC for approval. FE and FES have also entered into a total of $23 million in parental guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. A NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft GEIC and published a proposed rule on this subject in September of 2013. On July 17, 2014, the NRC rejected a separate request to suspend the licensing decision in the Davis-Besse proceeding to allow for a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On July 25, 2014, the NRC ASLB rejected a proposed contention on the Davis-Besse shield building.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. These inspections revealed that the cracking condition has propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term CSA with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claimed their performance was excused by the force majeure clause in the CSA and presented evidence at trial that they could not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for past damages/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that defendants still owed future damages, it remanded the calculation of those damages back to the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only, and a multi-day hearing was held beginning May 13, 2014. A ruling is expected in the fourth quarter of 2014. In a related proceeding before the same court, ICG is appealing a ruling by the court that prohibited their reliance on a price re-opener clause to limit future damages.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 9, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

11. SUPPLEMENTAL GUARANTOR INFORMATION

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

The Condensed Consolidating Statements of Income and Comprehensive Income for the three and six months ended June 30, 2014 and 2013, Condensed Consolidating Balance Sheets as of June 30, 2014 and December 31, 2013, and Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2014 and 2013, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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

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

OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(5)	(5)	—	5	(5)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	25	—	25	(25)	25
Other comprehensive income (loss)	17	(5)	25	(20)	17
Income taxes (benefits) on other comprehensive income (loss)	7	(1)	9	(8)	7
Other comprehensive income (loss), net of tax	10	(4)	16	(12)	10
COMPREHENSIVE INCOME (LOSS)	$(78)	$53	$116	$(168)	$(77)

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

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

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

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

For the Three Months Ended June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$1,425	$553	$457	$(983)	$1,452
OPERATING EXPENSES:					
Fuel	—	286	46	—	332
Purchased power from affiliates	1,050	—	70	(983)	137
Purchased power from non-affiliates	524	1	—	—	525
Other operating expenses	175	69	131	12	387
Provision for depreciation	2	32	44	(2)	76
General taxes	19	8	7	—	34
Total operating expenses	1,770	396	298	(973)	1,491
OPERATING INCOME (LOSS)	(345)	157	159	(10)	(39)
OTHER INCOME (EXPENSE):					
Loss on debt redemption	(32)	—	—	—	(32)
Investment income	1	—	(14)	(5)	(18)
Miscellaneous income, including net income from equity investees	171	3	—	(168)	6
Interest expense — affiliates	(5)	(1)	(3)	4	(5)
Interest expense — other	(12)	(27)	(14)	14	(39)
Capitalized interest	1	—	9	—	10
Total other income (expense)	124	(25)	(22)	(155)	(78)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(221)	132	137	(165)	(117)
INCOME TAXES (BENEFITS)	(150)	53	52	3	(42)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(71)	79	85	(168)	(75)
Discontinued operations (net of income taxes of $1) (Note 13)	—	4	—	—	4
NET INCOME (LOSS)	$(71)	$83	$85	$(168)	$(71)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					

NET INCOME (LOSS)	$(71)	$83	$85	$(168)	$(71)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(5)	(5)	—	5	(5)
Amortized gain on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available for sale securities	(8)	—	(8)	8	(8)
Other comprehensive income (loss)	(14)	(5)	(8)	13	(14)
Income tax benefits on other comprehensive income (loss)	(5)	(2)	(4)	6	(5)
Other comprehensive income (loss), net of tax	(9)	(3)	(4)	7	(9)
COMPREHENSIVE INCOME (LOSS)	$(80)	$80	$81	$(161)	$(80)

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

For the Six Months Ended June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$2,921	$1,084	$897	$(1,926)	$2,976
OPERATING EXPENSES:					
Fuel	—	533	99	—	632
Purchased power from affiliates	2,063	—	132	(1,926)	269
Purchased power from non-affiliates	1,029	2	—	—	1,031
Other operating expenses	337	143	262	24	766
Pensions and OPEB mark-to-market adjustments	—	—	—	—	—
Provision for depreciation	3	63	88	(3)	151
General taxes	39	19	13	—	71
Total operating expenses	3,471	760	594	(1,905)	2,920
OPERATING INCOME (LOSS)	(550)	324	303	(21)	56
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income	2	—	4	(7)	(1)
Miscellaneous income, including net income from equity investees	363	4	—	(359)	8
Interest expense — affiliates	(7)	(2)	(4)	7	(6)
Interest expense — other	(37)	(55)	(29)	30	(91)
Capitalized interest	1	—	18	—	19
Total other income (expense)	219	(53)	(11)	(329)	(174)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(331)	271	292	(350)	(118)
INCOME TAXES (BENEFITS)	(262)	104	110	6	(42)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(69)	167	182	(356)	(76)
Discontinued operations (net of income taxes of $3) Note (13)	—	7	—	—	7
NET INCOME (LOSS)	$(69)	$174	$182	$(356)	$(69)

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(69)	$174	$182	$(356)	$(69)
OTHER COMPREHENSIVE INCOME:					
Pensions and OPEB prior service costs	(11)	(10)	—	10	(11)
Amortized gain on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available-for-sale securities	(3)	—	(3)	3	(3)
Other comprehensive loss	(16)	(10)	(3)	13	(16)
Income tax benefits on other comprehensive loss	(6)	(4)	(2)	6	(6)
Other comprehensive loss, net of tax	(10)	(6)	(1)	7	(10)
COMPREHENSIVE INCOME (LOSS)	$(79)	$168	$181	$(349)	$(79)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of June 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	534	—	—	—	534
Affiliated companies	437	380	350	(692)	475
Other	70	19	8	—	97
Notes receivable from affiliated companies	421	605	125	(983)	168
Materials and supplies	71	179	216	—	466
Derivatives	238	—	—	—	238
Collateral	256	—	—	—	256
Prepayments and other	59	66	—	—	125
	2,086	1,251	699	(1,675)	2,361
PROPERTY, PLANT AND EQUIPMENT:					
In service	127	6,156	7,722	(383)	13,622
Less — Accumulated provision for depreciation	32	2,005	3,121	(190)	4,968
	95	4,151	4,601	(193)	8,654
Construction work in progress	6	161	515	—	682
	101	4,312	5,116	(193)	9,336
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,379	—	1,379
Investment in affiliated companies	6,060	—	—	(6,060)	—
Other	—	11	—	—	11
	6,060	11	1,379	(6,060)	1,390
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	184	58	—	(242)	—
Customer intangibles	86	—	—	—	86
Goodwill	23	—	—	—	23
Property taxes	—	7	12	—	19
Unamortized sale and leaseback costs	—	—	—	215	215
Derivatives	57	—	—	—	57
Other	47	279	1	(215)	112
	397	344	13	(242)	512
	$8,644	$5,918	$7,207	$(8,170)	$13,599
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$120	$193	$(23)	$291
Short-term borrowings-					
Affiliated companies	603	379	—	(982)	—
Other	300	8	—	—	308

Accounts payable-					
Affiliated companies	611	222	198	(610)	421
Other	110	149	—	—	259
Accrued taxes	182	26	19	(129)	98
Derivatives	200	—	—	—	200
Other	86	53	11	33	183
	2,093	957	421	(1,711)	1,760
CAPITALIZATION:					
Total equity	5,731	2,398	3,662	(6,032)	5,759
Long-term debt and other long-term obligations	712	2,133	1,049	(1,173)	2,721
	6,443	4,531	4,711	(7,205)	8,480
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	841	841
Accumulated deferred income taxes	15	—	826	(95)	746
Asset retirement obligations	—	188	856	—	1,044
Retirement benefits	23	171	—	(1)	193
Derivatives	43	—	—	—	43
Other	27	71	393	1	492
	108	430	2,075	746	3,359
	$8,644	$5,918	$7,207	$(8,170)	$13,599

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	539	—	—	—	539
Affiliated companies	938	787	227	(916)	1,036
Other	52	12	17	—	81
Notes receivable from affiliated companies	203	23	683	(909)	—
Materials and supplies	76	159	213	—	448
Derivatives	165	—	—	—	165
Collateral	136	—	—	—	136
Prepayments and other	52	50	7	—	109
	2,161	1,033	1,147	(1,825)	2,516
PROPERTY, PLANT AND EQUIPMENT:					
In service	104	6,105	6,645	(382)	12,472
Less — Accumulated provision for depreciation	28	1,953	2,962	(188)	4,755
	76	4,152	3,683	(194)	7,717
Construction work in progress	23	148	1,137	—	1,308
	99	4,300	4,820	(194)	9,025
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,276	—	1,276
Investment in affiliated companies	5,801	—	—	(5,801)	—
Other	—	11	—	—	11
	5,801	11	1,276	(5,801)	1,287
ASSETS HELD FOR SALE	—	122	—	—	122
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	131	—	(131)	—
Customer intangibles	95	—	—	—	95
Goodwill	23	—	—	—	23
Property taxes	—	15	26	—	41
Unamortized sale and leaseback costs	—	—	—	168	168
Derivatives	53	—	—	—	53
Other	81	228	18	(155)	172
	252	374	44	(118)	552
	$8,313	$5,840	$7,287	$(7,938)	$13,502
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$367	$547	$(23)	$892
Short-term borrowings-					

Affiliated companies	977	212	151	(909)	431
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	741	400	362	(738)	765
Other	94	196	—	—	290
Accrued taxes	204	23	23	(184)	66
Derivatives	110	—	—	—	110
Other	70	63	18	46	197
	2,197	1,265	1,101	(1,808)	2,755
CAPITALIZATION:					
Total equity	5,312	2,283	3,493	(5,776)	5,312
Long-term debt and other long-term obligations	712	1,860	742	(1,184)	2,130
	6,024	4,143	4,235	(6,960)	7,442
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	858	858
Accumulated deferred income taxes	32	—	736	(27)	741
Asset retirement obligations	—	187	828	—	1,015
Retirement benefits	22	163	—	—	185
Derivatives	14	—	—	—	14
Other	24	82	387	(1)	492
	92	432	1,951	830	3,305
	$8,313	$5,840	$7,287	$(7,938)	$13,502

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

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

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

For the Six Months Ended June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(687)	$390	$308	$(11)	$—
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	240	112	—	(352)	—
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(770)	(352)	(68)	11	(1,179)
Tender premiums	(67)	—	—	—	(67)
Other	(2)	(3)	—	—	(5)
Net cash provided from (used for) financing activities	901	(243)	(68)	(341)	249
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(7)	(163)	(180)	—	(350)
Nuclear fuel	—	—	(50)	—	(50)
Proceeds from asset sales	—	19	—	—	19
Sales of investment securities held in trusts	—	—	487	—	487
Purchases of investment securities held in trusts	—	—	(515)	—	(515)
Loans to affiliated companies, net	(207)	(7)	18	352	156
Other	—	3	—	—	3
Net cash used for investing activities	(214)	(148)	(240)	352	(250)
Net change in cash and cash equivalents	—	(1)	—	—	(1)
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$—	$2	$—	$—	$2

12. SEGMENT INFORMATION

FirstEnergy continues to have three reportable operating segments - Regulated Distribution, Regulated Transmission and Competitive Energy Services. The external reporting is consistent with the internal financial reporting used by FirstEnergy’s Chief Executive Officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources.

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

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,790 MWs of generation capacity.
The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.
The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM. This segment also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams, and modifying its hedging strategy to optimize risk management and market upside opportunities. As part of this, the Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility as was experienced in the first quarter of 2014. Going forward, the Competitive Energy Services segment expects to target a sales portfolio of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales, 10 to 20 million MWHs in block wholesale sales and 10 to 20 million MWHs of spot wholesale sales. As a result of these changes, the Competitive Energy Services segment incurred certain pre-tax charges in the second quarter of 2014 including an impairment of deferred advertising costs, specifically resulting from the elimination of selling efforts as discussed above, of approximately $22 million and severance related expenses of $7 million. Support for current customers in the channels to be exited will remain through their respective contract terms.

The Other/Corporate Segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment. Reconciling adjustments primarily consist of elimination of intersegment transactions.

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/Corporate	Reconciling Adjustments	Consolidated
	(In millions)					
June 30, 2014						
External revenues	$2,065	$ 191	$1,311	$ (31)	$(40)	$3,496
Internal revenues	—	—	182	—	(182)	—
Total revenues	2,065	191	1,493	(31)	(222)	3,496
Depreciation, amortization and deferrals	180	33	96	13	—	322
Investment income (loss)	15	—	21	2	(9)	29
Interest expense	147	30	48	30	7	262
Income taxes (benefits)	77	32	(65)	(30)	12	26
Income (loss) from continuing operations	158	63	(119)	(26)	(12)	64
Net income (loss)	158	63	(119)	(26)	(12)	64
Total assets	27,901	5,840	17,137	510	—	51,388
Total goodwill	5,092	526	800	—	—	6,418
Property additions	340	384	240	24	—	988
June 30, 2013						
External revenues	$2,038	$ 179	$1,368	$ (31)	$(47)	$3,507
Internal revenues	—	—	176	—	(176)	—
Total revenues	2,038	179	1,544	(31)	(223)	3,507
Depreciation, amortization and deferrals	220	31	112	9	—	372
Investment income (loss)	9	—	(16)	2	(10)	(15)
Interest expense	135	22	61	38	—	256
Income taxes (benefits)	108	30	(212)	8	4	(62)
Income (loss) from continuing operations	179	51	(343)	(52)	(3)	(168)
Net income (loss)	179	51	(339)	(52)	(3)	(164)
Total assets	26,936	4,797	17,910	514	—	50,157
Total goodwill	5,025	526	896	—	—	6,447
Property additions	283	97	185	21	—	586
Six Months Ended						
June 30, 2014						
External revenues	$4,615	$ 373	$2,833	$ (71)	$(72)	$7,678
Internal revenues	—	—	431	—	(431)	—
Total revenues	4,615	373	3,264	(71)	(503)	7,678
Depreciation, amortization and deferrals	311	66	187	24	—	588
Investment income	30	—	35	5	(19)	51
Interest expense	298	55	94	73	7	527

Income taxes (benefits)	202	62	(138)	(56)	4	74
Income (loss) from continuing operations	372	114	(243)	(58)	1	186
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	372	114	(157)	(58)	1	272
Property additions	609	601	558	41	—	1,809
June 30, 2013						
External revenues	$4,247	$ 355	$2,782	$ (58)	$(99)	$7,227
Internal revenues	—	—	392	—	(392)	—
Total revenues	4,247	355	3,174	(58)	(491)	7,227
Depreciation, amortization and deferrals	422	60	222	20	—	724
Investment income (loss)	27	—	(6)	3	(21)	3
Interest expense	270	45	134	65	—	514
Income taxes (benefits)	234	61	(236)	(11)	4	52
Income (loss) from continuing operations	389	102	(385)	(82)	—	24
Discontinued operations, net of tax	—	—	8	—	—	8
Net income (loss)	389	102	(377)	(82)	—	32
Property additions	719	186	468	39	—	1,412

13. DISCONTINUED OPERATIONS

On September 4, 2013, certain of FirstEnergy subsidiaries applied for authorization from the FERC to sell eleven hydroelectric power stations in Pennsylvania, Virginia and West Virginia to subsidiaries of Harbor Hydro, a subsidiary of LS Power. The asset purchase agreement was entered into on August 23, 2013, and amended and restated as of September 4, 2013. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million) which was allocated to the hydroelectric plants to be sold.

Pre-tax income for the hydroelectric facilities of $155 million (FES - $186 million) for the six months ended June 30, 2014, and $8 million and $14 million (FES - $5 million and $10 million) for the three and six months ended June 30, 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income (Loss). Included in income from discontinued operations in the six months ended June 30, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million (FES - $5 million) for the six months ended June 30, 2014 and $7 million and $13 million (FES - $6 million and $12 million) for the three and six months ended June 30, 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income (Loss).

14. IMPAIRMENT OF LONG-LIVED ASSETS

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the following generating units by October 9, 2013:

Generating Units	MW Capacity	Location
Hatfield's Ferry, Units 1-3	1,710	Masontown, Pennsylvania
Mitchell, Units 2-3	370	Courtney, Pennsylvania

As a result of this decision, in the second quarter of 2013, FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge is included within the results of the Competitive Energy Services segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

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

FIRSTENERGY CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Net income in the second quarter of 2014 was $64 million, or basic earnings of $0.16 per share ($0.15 diluted), compared with a net loss of $164 million, or basic and diluted losses of $0.39 per share of common stock in the second quarter of 2013. Net income (loss) and changes by segment are summarized below:

	Three Months Ended June 30			Six Months Ended June 30		
	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
	(In millions, except per share)					
Net Income (Loss) By Segment:						
Regulated Distribution	$158	$179	$(21)	$372	$389	$(17)
Regulated Transmission	63	51	12	114	102	12
Competitive Energy Services	(119)	(339)	220	(157)	(377)	220
Other and reconciling adjustments	(38)	(55)	17	(57)	(82)	25
FirstEnergy Corp.	$64	$(164)	$228	$272	$32	$240
Earnings per share - Basic	$0.16	$(0.39)	$0.55	$0.65	$0.08	$0.57
Earnings per share - Diluted	$0.15	$(0.39)	$0.54	$0.65	$0.08	$0.57

Three months ended June 30, 2014 compared to the three months ended June 30, 2013

The Regulated Distribution segment's earnings were impacted by the following:

- Higher distribution deliveries of 0.5% across all customer classes reflecting increased usage in the industrial and commercial sectors, partially offset by reduced weather-related usage in the residential sector.
- Increased regulated generation earnings primarily associated with the Harrison/Pleasants asset transfer in October of 2013. Currently, a return on and of the Harrison Plant costs are included as a temporary surcharge billed to all customers.
- Increased distribution operation and maintenance activities and pension and OPEB costs.
- Increased depreciation expense, primarily associated with a higher asset base.
- Increased interest expense primarily associated with the financing of the Harrison Plant and a 2013 debt issuance at JCP&L of $500 million.
- Other items impacting the Regulated Distribution Segment's earnings include the following pre-tax charges:

There were no impairments on NDT investments in the second quarter of 2014 compared to $7 million in the second quarter of 2013.

Regulatory charges of $11 million in the second quarter of 2014 compared to $11 million in the second quarter of 2013.

The Regulated Transmission segment's earnings were impacted by the following:

- Higher revenue principally at ATSI and TrAIL reflecting incremental cost of service and rate base recovery resulting from their annual rate filings effective June 2013 and June 2014.
- Increased operating expenses principally due to higher property taxes and depreciation associated with a higher asset base.

The Competitive Energy Services segment's operations were impacted by the following:

- Reduced revenues resulting from Competitive Energy Services’ strategy to be more selective in customers targeted in response to the current market environment, partially offset by higher unit prices and higher capacity revenues.
- Additional purchased power at higher prices resulting from outages.
- Higher capacity expenses associated with sales obligations resulting from increased capacity prices.
- Lower operating expenses, primarily related to lower retail and marketing related expenses, partially offset by higher nuclear operating costs.
- Reduced fuel and operating expenses, such as operating and maintenance, depreciation and general taxes, associated with the Harrison/Pleasants asset transfer and the deactivation of certain power plants during 2013, were offset by the cost of replacing that generation.
- Lower interest expense associated with the redemption and repurchase of long-term debt at FES and AE Supply in 2013.
- Other items impacting the Competitive Energy Services Segment's earnings include the following pre-tax charges:

Loss on debt redemptions were $1 million in the second quarter of 2014 compared to $32 million in the second quarter of 2013.
Losses related to commodity mark-to-market adjustments were $62 million in the second quarter of 2014. There were no mark-to-market adjustments in the second quarter of 2013.
Costs associated with plant closings were $82 million in the second quarter of 2014 compared to $536 million in the second quarter of 2013 primarily resulting from the impairment of the Hatfield's Ferry and Mitchell power plants in the second quarter of 2013, partially offset by increased costs related to fuel contract terminations.
Charges associated with the segment's change in retail sales strategy were $46 million in the second quarter of 2014. The charges primarily include the impairment of deferred advertising costs and severance related expenses.
Amortization expense associated with purchase accounting adjustments on commodity contracts were $11 million in the second quarter of 2014 compared to $15 million in the second quarter of 2013.
There were no PJM charges associated with deactivated plants in the second quarter of 2014 compared to $5 million in the second quarter of 2013.
Impairments on securities held in NDT were $1 million in the second quarter of 2014 compared to $39 million in the second quarter of 2013.
Costs associated with the segment's Signal Peak investment were $6 million in the second quarter of 2014.

The Other segment's operations were impacted by the following:

- A lower effective income tax rate primarily from a reduction in deferred tax liabilities associated with changes in state apportionment factors, a valuation allowance recorded in 2013 against state and local NOL carryforwards.
- Other items impacting the Other Segment's earnings include the following pre-tax changes:

There were no gains or losses related to debt redemptions in the second quarter of 2014 compared to $8 million of gains in the second quarter of 2013.

Executive Summary

FirstEnergy holds a large and diverse mix of assets, featuring an electric distribution service area and transmission footprint that are among the largest in the nation, as well as a significant competitive generation fleet and competitive sales business.

As a result of the challenging environment in the Competitive Energy Services segment, FirstEnergy has redirected its growth strategy to pursue more predictable and sustainable long-term growth opportunities in its regulated businesses.

FirstEnergy's strategy is to focus on growth through investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion “Energizing the Future” investment plan that began in 2014 and will continue through 2017 to upgrade and expand the transmission system owned by FirstEnergy’s Regulated Transmission segment. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. FirstEnergy expects to fund these investments through a combination of debt, previously announced equity issuances through a stock investment plan and, to the extent available, employee benefit plans, and cash. As a result of these investments, Regulated Transmission's earnings are expected to grow modestly over the next two years and then accelerate as the investments are fully recognized in rates. In total, FirstEnergy has identified at least $7 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for growth in the years beyond 2017.

In the territory served by FirstEnergy’s Regulated Distribution segment, the economy has struggled to recover from the recession, and there continues to be weak demand for electricity as evidenced by flat distribution sales over the last three years. However, the location of the Marcellus and Utica shale gas region provides optimism for growth over the long term. More than 400 MW of new industrial demand associated with shale gas activity is expected to come online in FirstEnergy's region by the end of 2014, with more than 500 MW of additional planned expansion at customer facilities through 2018. These projects alone are expected to result in more industrial growth over the next two years, and a robust pipeline of mid-stream projects represent further opportunities for additional growth, as well as the potential for growth in the residential class.

FirstEnergy is also pursuing regulatory initiatives across its utility footprint, including, as further described below, a rate case application in West Virginia filed in April 2014, a rate case application in PA, and an ESP IV filing in Ohio, both of which were filed in August 2014, as well as the current rate proceeding in New Jersey.

Additionally, FirstEnergy continues to focus on maintaining the value of its competitive business, which has been challenged over the last several years by prolonged weak demand for power, low capacity payments and energy prices. FirstEnergy has reduced the size and shifted the mix of its generating assets, as well as reduced operating expenses and capital expenditures. As a result, the remaining competitive fleet is more cost-effective, efficient and environmentally sound. In addition, FirstEnergy is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation in excess of committed sales, eliminate load obligations that do not adequately cover risk premiums, pursue more certain revenue streams, and modify its hedging strategy to optimize risk management and market upside opportunities. As part of this, the Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility as was experienced in the first quarter of 2014. Going forward, the Competitive Energy Services segment expects to target a sales portfolio of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales, 10 to 20 million in block wholesale sales and 10 to 20 million of spot wholesale sales. Support for current customers in the channels to be exited will remain through their respective contract terms.

While it cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last two years to reposition this business for such a recovery.

In alignment with FirstEnergy’s strategy to focus on growing the Regulated Transmission and Regulated Distribution segments and reposition the Competitive Energy Services segment, FirstEnergy is also focused on reducing balance sheet risk, maintaining investment grade metrics, and improving the business risk profile at each of its businesses. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue or refinance debt. Finally, at the competitive business, FirstEnergy completed the sale of certain hydro assets for approximately $394 million on February 12, 2014. The actions taken in 2013 and the first half of 2014, and those planned for the remainder of 2014 are expected to support a primarily regulated investment strategy.

Operational Matters

Nuclear Operations

On May 8, 2014, the Davis-Besse Nuclear Power station returned to service following an outage to install two new steam generators, replace 80 of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities which began on February 1, 2014. These activities, including amounts spent in prior years in preparation for this outage, represent an investment of approximately $600 million by FES at Davis-Besse.

On May 23, 2014, Beaver Valley Unit 2 returned to service following a scheduled refueling and maintenance outage that began on April 19, 2014. During the outage, approximately one third of the plant's 157 fuel assemblies were exchanged. In addition, numerous inspections and preventative maintenance and improvement projects were completed to ensure continued safe and reliable operations. The unit also completed a number of projects in preparation for replacement of the unit's three steam generators and reactor head, expected to occur in 2020, including installation of a heavy-duty crane system in containment.

Under contracts with the DOE, FirstEnergy has paid a regular quarterly fee to the DOE’s Nuclear Waste Fund for the disposal of spent nuclear fuel of approximately 1.0 mill per kWh of electricity generated by FE's nuclear power stations. The fees have been expensed as incurred as a component of fuel expense and have amounted to approximately $30 million per year. Beginning May 16, 2014, the spent nuclear fuel disposal fees were set to zero by the DOE as mandated by the U.S. Court of Appeals for the D.C. Circuit, until Congress establishes a new spent fuel disposal program or restarts the original program at Yucca Mountain, Nevada.

Employee Relations

On April 14, 2014, a lock-out of UWUA Local 180 members ended. The 20-week lock-out started on November 25, 2013. The employees returned to work under the terms of PN's Last, Best and Final Offer of November 6, 2013. The Last, Best and Final Offer included wage increases, increases in shift premiums and meal allowances, and additional operational improvements, such as a new job classification intended to increase customer service and efficiency. Employees were reinstated to the positions they held prior to the lock-out. The CBA with IBEW Local 272, which represents approximately 300 employees at the Bruce Mansfield Plant expired on February 16, 2014. The CBA with Local 102, which represents approximately 700 employees at WP and PE, expired on April 30, 2013. Additionally, UWUA Local 304, representing approximately 160 employees at the Harrison Plant, are currently working without a negotiated CBA. FirstEnergy continues to engage in negotiations with each of Locals 180, 272, 304 and 102, and work continuation plans are in place in the event of a work stoppage. FE reached settlement agreements on final contract language with Locals 180 and 304 on July 30, 2014 which are subject to a ratification process by each Local.

MATS Update

FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $370 million (Competitive Energy Services segment of approximately $178 million and Regulated Distribution segment of approximately $192 million), reduced from the previous estimate of $465 million.

PJM Capacity Auction

In May 2014, PJM held its annual auction for capacity for the 2017/2018 planning year. The following table summarizes PJM capacity auction results for the Competitive Energy Services segment over the last five annual auctions held:

	Competitive MWs Cleared[1]				
Zone	2013/2014	2014/2015	2015/2016	2016/2017[2]	2017/2018[2]
ATSI	6,830	5,645	7,070	3,845	4,285
RTO	5,670	4,720	5,040	3,460	4,515
MAAC	85	85	80	80	75
EMAAC	55	55	55	55	55
	12,640	10,505	12,245	7,440	8,930

	Capacity Prices				
Zone	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
ATSI	$27.73	$125.99	$357.00	$114.23	$120.00
RTO	$27.73	$125.99	$136.00	$59.37	$120.00
MAAC	$226.15	$136.50	$167.46	$119.13	$120.00
EMAAC	$245.00	$136.50	$167.46	$119.13	$120.00

(1) Does not reflect any additional sales after the Base Residual Auction.
(2) Available MWs for the 2016/2017 and 2017/2018 incremental auctions are 3,510 MWs and 2,455 MWs, respectively.

Bruce Mansfield Operations

In August 2014, FirstEnergy announced that, while it will continue to operate and maintain the Bruce Mansfield Plant, it is minimizing capital expenditures at the plant as a result of current market conditions until the results from an upcoming incremental capacity auction or perhaps the PJM 2015 base residual auction are known. It will take approximately two years to complete a new dewatering facility that is necessary for the plant to operate beyond December 31, 2016, when the Little Blue Run disposal site closes. Based on market conditions, FirstEnergy may delay this project, which may push out the timing of the capital expenditures and possibly impact the nature and timing of the outage.

Regulatory Matters

WV Rate Filing

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%, based on an historic 2013 test year. 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. On June 13, 2014, MP and PE amended their filing to add an additional $7.5 million of additional revenues to reimburse their expected costs of implementing monthly meter reading for residential and small commercial customers. The proposed total rate increase request, including the cost of the vegetation management program and monthly meter reading, is approximately $152 million, or 14.7%. MP and PE anticipate a decision from the WVPSC in February 2015.

Ohio ESP IV Filing

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled "Powering Ohio's Progress". The Ohio Companies have requested a decision by the PUCO by April 8, 2015. The material terms of the proposed plan include:

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

PA Rate Filing

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings request approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. The filings also propose several new cost recovery riders as well as revisions to certain existing cost recovery riders. An order on the proposed increases is expected in April 2015.

PJM RPM Auctions - Complaint Regarding 2014 PJM BRA

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP, just as if DR were a traditional energy resource. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC therefore lacked jurisdiction to regulate DR, such as via the PJM tariffs and programs. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was receiving a double payment (LMP plus the savings of foregone energy purchases). On July 7, 2014, FERC and other parties requested that the U.S. Court of Appeals for the D.C. Circuit grant rehearing en banc, which is a procedural path to ask the full U.S. Court of Appeals for the D.C. Circuit to reconsider the panel's decision. On July 11, 2014, FERC clarified that it is petitioning for rehearing en banc solely regarding the issue of jurisdiction, and not any other issue, including compensation and cost allocation. On August 4, 2014, and acting pursuant to a court order, the original trade group petitioners and Old Dominion Electric Cooperative filed a joint response to FERC's petition for rehearing en banc. On May 23, 2014, FESC, on behalf of FE entities with market-based rate authority, filed a complaint asking FERC to direct PJM to remove all portions of the PJM OATT, which allows or requires PJM to include DR in the PJM capacity market, and to invalidate the results of the May 2014 RPM capacity auction on the grounds that the U.S. Court of Appeals for the D.C. Circuit’s May 23, 2014 decision required removal of DR from the wholesale capacity markets. In a subsequent pleading, FESC stated its intent to file an amended complaint. FESC expects to file the amended complaint in late summer 2014. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

Pennsylvania Smart Meter Filing Update

On June 5, 2014, the PPUC approved the Pennsylvania Companies' March 2014 amended smart meter deployment plan that requested approval of a modification to the deployment schedule to allow the entire PP smart meter system (approximately 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, and approximately 98.5% of all smart meters and related equipment to be built throughout each of the Pennsylvania Companies' service territories by mid-2019, instead of the end of 2019.

Financial Matters

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 PCRBs for remarketing subject to future market and other conditions. Additionally, on April 1, 2014, ME retired $150 million of long-term debt at maturity.

On May 19, 2014, FET issued $600 million of 4.35% senior notes due 2025 and $400 million of 5.45% senior notes due 2044. Proceeds received from the issuance of the senior notes were used to (i) repay borrowings under its revolving credit facility and the FirstEnergy unregulated company money pool; (ii) fund a capital contribution to ATSI; and (iii) for working capital needs and other general business purposes.

In addition, in the second quarter of 2014, FG and NG remarketed approximately $57 million and $164 million, respectively, of PCRBs previously held by the companies. The bonds were remarketed with a fixed interest rate of 3.50% per annum with a mandatory put date of June 1, 2020.

On June 11, 2014, ME and PN issued $250 million of 4% senior notes due 2025 and $200 million of 4.15% senior notes due 2025, respectively. Proceeds received from the issuance of the senior notes were used to repay ME and PN's borrowings under the FirstEnergy revolving credit facility and the FirstEnergy regulated utility money pool.

FIRSTENERGY’S BUSINESS

FirstEnergy continues to have three reportable operating segments - Regulated Distribution, Regulated Transmission and Competitive Energy Services. The external reporting is consistent with the internal financial reporting used by FirstEnergy’s Chief Executive Officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources.

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

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM. This segment also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams, and modifying its hedging strategy to optimize risk management and market upside opportunities. As part of this, the Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility as was experienced in the first quarter of 2014. Going forward, the Competitive Energy Services segment expects to target a sales portfolio of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales, 10 to 20 million MWHs in block wholesale sales and 10 to 20 million MWHs of spot wholesale sales. As a result of these changes, the Competitive Energy Services segment incurred certain pre-tax charges in the second quarter of 2014 including an impairment of deferred advertising costs, specifically resulting from the elimination of selling efforts as discussed above, of approximately $22 million and severance related expenses of $7 million. Support for current customers in the channels to be exited will remain through their respective contract terms.

The Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS, among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of June 30, 2014, committed sales for calendar year 2014 are 98.1 million MWH. For the six months from July to December 2014, supply from expected generation and committed purchases is a pproximately 106% of committed sales under normal weather conditions. As of June 30, 2014, committed sales for 2015, 2016 and 2017 are approximately 54 million MWHs, 28 million MWHs and 20 million MWHs, respectively. On average, the Competitive Energy Services segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs related to purchased power agreements for wind, solar and its entitlement to OVEC. The Competitive Energy Services segment fulfills the difference between committed sales, which is based on estimated customer usage, assuming normal weather, and electricity generated, through forward contracts and options, generation produced by its peaking units and purchasing power on the wholesale market, as necessary.

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 12, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

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

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

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy’s segments. A reconciliation of segment financial results is provided in Note 12, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with the sale of hydro assets discussed in additional detail in Note 13, Discontinued Operations.

Summary of Results of Operations — Second Quarter 2014 Compared with Second Quarter 2013

Financial results for FirstEnergy's business segments in the second quarter of 2014 and 2013 were as follows:

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

Second Quarter 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$1,977	$179	$1,324	$(49)	$3,431
Other	61	—	44	(29)	76
Internal	—	—	176	(176)	—
Total Revenues	2,038	179	1,544	(254)	3,507
Operating Expenses:					
Fuel	75	—	553	—	628
Purchased power	762	—	280	(176)	866
Other operating expenses	402	33	534	(83)	886
Provision for depreciation	151	28	112	9	300
Amortization of regulatory assets, net	69	3	—	—	72
General taxes	172	14	49	5	240
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	1,631	78	2,001	(245)	3,465
Operating Income (Loss)	407	101	(457)	(9)	42
Other Income (Expense):					
Loss on debt redemptions	—	—	(32)	8	(24)
Investment income (loss)	9	—	(16)	(8)	(15)
Interest expense	(135)	(22)	(61)	(38)	(256)
Capitalized financing costs	6	2	11	4	23
Total Other Expense	(120)	(20)	(98)	(34)	(272)
Income (Loss) From Continuing Operations Before Income Taxes	287	81	(555)	(43)	(230)
Income taxes (benefits)	108	30	(212)	12	(62)
Income (Loss) From Continuing Operations	179	51	(343)	(55)	(168)
Discontinued Operations, net of tax	—	—	4	—	4
Net Income (Loss)	$179	$51	$(339)	$(55)	$(164)

Changes Between Second Quarter 2014 and Second Quarter 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$40	$12	$(60)	$(8)	$(16)
Other	(13)	—	3	15	5
Internal	—	—	6	(6)	—
Total Revenues	27	12	(51)	1	(11)
Operating Expenses:					
Fuel	54	—	(132)	—	(78)
Purchased power	(16)	—	239	(6)	217
Other operating expenses	78	(2)	50	9	135
Provision for depreciation	13	2	(16)	3	2
Amortization of regulatory assets, net	(53)	—	—	1	(52)
General taxes	(6)	4	(10)	—	(12)
Impairment of long-lived assets	—	—	(473)	—	(473)
Total Operating Expenses	70	4	(342)	7	(261)
Operating Income (Loss)	(43)	8	291	(6)	250
Other Income (Expense):					
Loss on debt redemptions	—	—	31	(8)	23
Investment income	6	—	37	1	44
Interest expense	(12)	(8)	13	1	(6)
Capitalized financing costs	(3)	14	(1)	(1)	9
Total Other Expense	(9)	6	80	(7)	70
Income (Loss) From Continuing Operations Before Income Taxes	(52)	14	371	(13)	320
Income taxes (benefits)	(31)	2	147	(30)	88
Income (Loss) From Continuing Operations	(21)	12	224	17	232
Discontinued Operations, net of tax	—	—	(4)	—	(4)
Net Income (Loss)	$(21)	$12	$220	$17	$228

Regulated Distribution — Second Quarter 2014 Compared with Second Quarter 2013

Net income decreased $21 million in the second quarter of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

The $27 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2014	2013	Increase (Decrease)
	(In millions)		
Distribution services	$854	$897	$(43)
Generation sales:			
Retail	924	917	7
Wholesale	123	61	62
Total generation sales	1,047	978	69
Transmission	116	102	14
Other	48	61	(13)
Total Revenues	$2,065	$2,038	$27

The decrease in distribution services revenue is primarily related to a decrease in revenues from the ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013 and a rider rate decrease associated with the recovery of energy efficiency program costs for the Pennsylvania Companies. Distribution deliveries increased by 0.5% in the second quarter of 2014 compared to the same period of 2013. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended June 30 2014	2013	Increase (Decrease)
	(In thousands)		
Residential	11,918	12,128	(1.7)%
Commercial	10,355	10,241	1.1%
Industrial	12,761	12,495	2.1%
Other	147	142	3.5%
Total Electric Distribution MWH Deliveries	35,181	35,006	0.5%

Lower deliveries to residential customers primarily reflect decreased weather-related usage resulting from heating degree days that were 6% below 2013 and 10% below normal, as well as cooling degree days that were 7% below 2013, but 3% above normal. Higher deliveries to commercial customers reflect increased economic activity in that sector. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical, petroleum, and paper customers. For 2014, FirstEnergy continues to expect an increase in industrial sales, with a majority of that increase resulting from shale gas activities. Additionally, FirstEnergy expects growth in the industrial sector beyond 2014 for potential shale gas projects. As new gas fields are developed, the opportunity for additional manufacturing expansion could further support growth.

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The following table summarizes the price and volume factors contributing to the $69 million increase in generation revenues for the second quarter of 2014 compared to the same period of 2013:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(13)
Change in prices	20
	7
Wholesale:	
Effect of increase in sales volumes	56
Change in prices	6
	62
Increase in Generation Revenues	$69

The decrease in retail generation sales volumes was primarily due to decreased weather-related usage, as described above, and increased customer shopping in Ohio and Pennsylvania. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 82% from 81% for the Ohio Companies and 69% from 67% for the Pennsylvania Companies. The increase in retail generation prices reflects higher Pennsylvania PTC prices, the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs effective June 2013. Additionally, the impact on retail generation prices resulting from MP's Temporary Transaction Surcharge associated with the Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs.

The increase in wholesale generation revenues of $62 million reflects increased volume resulting from the Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of net capacity in October 2013 and higher energy prices in the second quarter of 2014 as compared to the same period of 2013.

The increase in transmission revenues of $14 million reflects higher reactive power revenues at MP and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013. Network transmission costs are now recovered through WP's generation rate as discussed above.

Other revenues decreased $13 million primarily due to less customer requested work in the second quarter of 2014 compared to the same period of 2013.

Operating Expenses —

Total operating expenses increased $70 million primarily due to the following:

- Fuel expense was $54 million higher in the second quarter of 2014 primarily related to increased generation as a result of the Harrison/Pleasants asset transfer in October of 2013.

- Purchased power costs were $16 million lower primarily due to a decrease in volumes resulting from increased customer shopping and lower weather-related usage, partially offset by higher unit power supply costs.

Source of Change in Purchased Power	Increase(Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 34
Change due to decreased volumes	(46)
	(12)
Purchases from affiliates:	
Change due to increased unit costs	10
Change due to decreased volumes	(5)
	5
Increase in costs deferred	(9)
Decrease in Purchased Power Costs	$ (16)

- Other operating expenses increased $78 million primarily due to:

- Higher transmission expenses of $7 million primarily due to PJM transmission costs associated with the Harrison/Pleasants asset transfer and higher PJM charges to the Ohio Companies, which are recovered through the NMB transmission rider discussed above,

- Higher distribution operating and maintenance expenses of $34 million primarily due to a greater focus on maintenance activities, including $5 million of higher vegetation management expenses in West Virginia, which was deferred for future recovery,

- Higher pension and OPEB costs of $12 million primarily associated with lower amortization of prior service cost credits,

- Increased regulated generation operating and maintenance expenses of $13 million, reflecting increased costs associated with the Harrison/Pleasants asset transfer and a planned outage at Fort Martin.

- Depreciation expense increased $13 million due to a higher asset base, including $7 million associated with the Harrison/Pleasants asset transfer.

- Net amortization of regulatory assets decreased $53 million primarily due to a reduction of NUG cost recovery at ME and PN, decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies, a reduction to the Ohio Companies' generation cost recovery and the deferral of vegetation management expenses in West Virginia.

- General taxes decreased $6 million due to lower revenue related taxes.

Other Expense —

Other expense increased $9 million in the second quarter of 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million for the financing of the Harrison/Pleasants asset transfer and at JCP&L resulting from a new debt issuance of $500 million in 2013, partially offset by lower OTTI on NDT investments at OE and TE.

Income Taxes —

Regulated Distribution’s effective tax rate was 32.8% and 37.6% for the quarter ended June 30, 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors and an increase in the benefit of AFUDC equity flow through.

Regulated Transmission — Second Quarter 2014 Compared with Second Quarter 2013

Net income increased $12 million in the second quarter of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues increased $12 million principally at ATSI and TrAIL reflecting incremental cost of service and rate base recovery resulting from their annual rate filings effective June 2013 and June 2014.

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

	Three Months Ended June 30		Increase
Revenues by Transmission Asset Owner	2014	2013	(Decrease)
	(In millions)		
ATSI	$56	$51	$5
TrAIL	56	48	8
PATH	3	5	(2)
Utilities	76	75	1
Total Revenues	$191	$179	$12

Operating Expenses —

Total operating expenses increased $4 million principally due to higher property taxes and depreciation.

Other Income —

Other income increased $6 million in the second quarter of 2014 primarily due to higher capitalized financing costs of $14 million resulting from increased CWIP, partially offset by increased interest expense resulting from new debt issuances of $1.0 billion at FET.

Income Taxes —

Regulated Transmission’s effective tax rate was 33.7% and 37.0% for the quarter ended June 30, 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors and an increase in the benefit of AFUDC equity flow through.

Competitive Energy Services — Second Quarter 2014 Compared with Second Quarter 2013

Net losses decreased $220 million in the second quarter of 2014, compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues decreased $51 million in the second quarter of 2014, compared to the same period of 2013, primarily due to decreased sales volumes in the Direct channel, partially offset by higher Structured Sales volumes and higher unit prices in Direct, Governmental Aggregation, and POLR and Structured sales channels.

The decrease in total revenues resulted from the following sources:

	Three Months Ended June 30		Increase
Revenues by Type of Service	2014	2013	(Decrease)
	(In millions)		
Direct	$620	$725	$(105)
Governmental Aggregation	278	273	5
Mass Market	100	99	1
POLR and Structured	321	282	39
Wholesale	94	88	6
Transmission	33	33	—

Other	47	44	3
Total Revenues	$1,493	$1,544	$(51)

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MWH Sales by Channel	Three Months Ended June 30		Increase (Decrease)
	2014	2013	
	(In thousands)		
Direct	11,831	14,008	(15.5)%
Governmental Aggregation	4,652	4,776	(2.6)%
Mass Market	1,503	1,491	0.8 %
POLR and Structured	6,270	5,541	13.2 %
Wholesale	21	593	(96.5)%
Total MWH Sales	24,277	26,409	(8.1)%

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

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease)			
	Sales Volumes	Prices	Capacity Revenue	Total
	(In millions)			
Direct	$(112)	$7	$—	$(105)
Governmental Aggregation	(7)	12	—	5
Mass Market	1	—	—	1
POLR and Structured Sales	33	6	—	39
Wholesale	(19)	—	25	6

The decrease in Direct revenues of $105 million resulted from lower sales volumes from commercial and industrial customers, partially offset by higher unit prices. Direct sales volumes decreased due to Competitive Energy Services' strategy to be more selective in customers targeted in response to the current market environment. The increase in Governmental Aggregation revenues of $5 million primarily reflects increased unit prices, partially offset by decreased weather-related usage resulting from heating degree days that were 6% lower and cooling degree days that were 7% lower than the second quarter of 2013. The Direct, Governmental Aggregation and Mass Market customer base was 2.6 million as of June 30, 2014 compared to 2.7 million as of June 30, 2013. Higher unit prices as described above resulted from increased channel pricing.

The increase in POLR and structured sales of $39 million was due to higher structured sales volumes and higher POLR rates associated with recent auctions, partially offset by lower POLR sales volumes due to decreased weather-related usage.

Wholesale revenues increased $6 million, primarily due to an increase in capacity revenue from higher capacity prices, partially offset by a decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available to sell primarily as a result of the Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013 and increased outages.

Other revenue increased $3 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the second quarter of 2013. Competitive Energy Services earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased by $342 million in the second quarter of 2014 due to the following:

- Fuel costs decreased $132 million primarily due to lower volumes primarily associated with the Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013, and an increase in fossil outages, partially offset by a slight increase in nuclear generation. Higher fossil unit prices from increased peaking generation were partially offset by lower nuclear unit prices as a result of the suspension of the DOE disposal fee, which became effective May 16, 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. In the second quarter of 2014, a long-term fuel supply agreement was terminated for approximately $67 million while settlements associated with damages on coal and transportation contracts amounted to $33 million in the second quarter of 2013.

- Purchased power costs increased $239 million due to higher volumes ($170 million), increased prices ($23 million), and higher capacity expenses ($70 million), partially offset by gains on financially settled contracts ($24 million). Higher purchased volumes were primarily due to lower available generation resulting from outages, the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013. The increase in capacity expense was the result of higher capacity rates.

- Fossil operating costs decreased $6 million due primarily to lower labor costs resulting from previously deactivated units and the Harrison/Pleasants asset transfer.

- Nuclear operating costs increased $20 million as a result of higher contractor, materials and equipment costs associated with refueling outages. There were two refueling outages in the second quarter of 2014 as compared to one outage in the second quarter of 2013.

- Transmission expenses decreased $6 million due primarily to lower congestion and network costs, partially offset by network expenses associated with POLR sales in Pennsylvania that became the responsibility of suppliers effective June 1, 2013.
- General taxes decreased $10 million due primarily to lower payroll taxes as a result of lower labor costs noted above, lower property taxes due to the Harrison/Pleasants asset transfer, lower gross receipts taxes and reduced Ohio property taxes.
- Impairments of long-lived assets decreased by $473 million due to the impairment of two unregulated, coal-fired generating plants in the second quarter of 2013. The two plants were deactivated in October of 2013.
- Depreciation expense decreased $16 million primarily due to a reduction in the asset base as a result of plant deactivations and the Harrison/Pleasants asset transfer noted above, partially offset by capital assets placed in service.

- Other operating expenses increased $42 million primarily due to an increase in mark-to-market expenses on commodity contract positions and an impairment of deferred advertising costs of $22 million associated with the elimination of future selling efforts in the mass market and medium commercial-industrial sales channels, partially offset by lower severance costs primarily associated with 2013 plant deactivations, leasehold costs from the Ohio Companies and retail and marketing related costs.

Other Expense —

Total other expense in the second quarter of 2014 decreased $80 million compared to the same period of 2013 due to the absence of a $31 million loss on debt redemption in connection with senior notes that were repurchased in 2013, lower OTTI and higher investment income of $37 million primarily on NDT investments, and lower net interest expense of $12 million due to debt redemptions in 2013.

Income Tax Benefits —

Competitive energy services effective tax rate was 35.3% and 38.2% for the quarter ended June 30, 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on a pre-tax loss, primarily resulted from changes in state apportionment factors.

Other — Second Quarter 2014 Compared with Second Quarter 2013

Financial results from other operating segments and reconciling items, including interest expense on holding company debt, corporate support services revenues and expenses and income taxes, resulted in a $17 million increase in net income in the second quarter of 2014 compared to the same period of 2013. The increase in net income was primarily due to reduced income tax expense resulting from the recognition of a valuation allowance against state and local NOL carryforwards in 2013. Additionally, during the second quarter of 2014, FirstEnergy terminated certain interest rate swap agreements that resulted in a net benefit to interest expense of approximately $6 million.

Summary of Results of Operations — First Six Months of 2014 Compared with First Six Months of 2013

Financial results for FirstEnergy's business segments in the first six months of 2014 and 2013 were as follows:

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

First Six Months 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,130	$355	$2,696	$(93)	$7,088
Other	117	—	86	(64)	139
Internal	—	—	392	(392)	—
Total Revenues	4,247	355	3,174	(549)	7,227
Operating Expenses:					
Fuel	162	—	1,096	—	1,258
Purchased power	1,637	—	567	(392)	1,812
Other operating expenses	817	63	1,060	(172)	1,768
Provision for depreciation	295	56	222	20	593
Amortization of regulatory assets, net	127	4	—	—	131
General taxes	354	26	109	16	505
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	3,392	149	3,527	(528)	6,540
Operating Income (Loss)	855	206	(353)	(21)	687
Other Income (Expense):					
Loss on debt redemptions	—	—	(149)	8	(141)
Investment income (loss)	27	—	(6)	(18)	3
Interest expense	(270)	(45)	(134)	(65)	(514)
Capitalized financing costs	11	2	21	7	41
Total Other Expense	(232)	(43)	(268)	(68)	(611)
Income (Loss) From Continuing Operations Before Income Taxes	623	163	(621)	(89)	76
Income taxes (benefits)	234	61	(236)	(7)	52
Income (Loss) From Continuing Operations	389	102	(385)	(82)	24
Discontinued Operations, net of tax	—	—	8	—	8
Net Income (Loss)	$389	$102	$(377)	$(82)	$32

Changes Between First Six Months 2014 and First Six Months 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$388	$18	$42	$(14)	$434
Other	(20)	—	9	28	17
Internal	—	—	39	(39)	—
Total Revenues	368	18	90	(25)	451
Operating Expenses:					
Fuel	120	—	(211)	—	(91)
Purchased power	90	—	675	(39)	726
Other operating expenses	290	2	133	10	435
Provision for depreciation	31	4	(35)	3	3
Amortization (deferral) of regulatory assets, net	(142)	2	—	1	(139)
General taxes	(1)	9	(16)	2	(6)
Impairment of long-lived assets	—	—	(473)	—	(473)
Total Operating Expenses	388	17	73	(23)	455
Operating Income (Loss)	(20)	1	17	(2)	(4)
Other Income (Expense):					
Loss on debt redemptions	—	—	141	(8)	133
Investment income	3	—	41	4	48
Interest expense	(28)	(10)	40	(15)	(13)
Capitalized financing costs	(4)	22	1	1	20
Total Other Expense	(29)	12	223	(18)	188
Income (Loss) From Continuing Operations Before Income Taxes	(49)	13	240	(20)	184
Income taxes (benefits)	(32)	1	98	(45)	22
Income (Loss) From Continuing Operations	(17)	12	142	25	162
Discontinued Operations, net of tax	—	—	78	—	78
Net Income (Loss)	$(17)	$12	$220	$25	$240

Regulated Distribution — First Six Months of 2014 Compared with First Six Months of 2013

Net income decreased $17 million in the first six months of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

The $368 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2014	2013	Increase (Decrease)
	(In millions)		
Distribution services	$1,837	$1,868	$(31)
Generation sales:			
Retail	2,029	1,922	107
Wholesale	376	122	254
Total generation sales	2,405	2,044	361
Transmission	276	218	58
Other	97	117	(20)
Total Revenues	$4,615	$4,247	$368

The decrease in distribution services revenue is primarily related to a decrease in revenues from the ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013 and a rider rate decrease associated with the recovery of energy efficiency program costs for the Pennsylvania Companies. This was partially offset by higher electric distribution MWH deliveries as described below and an increase in the Ohio Companies' DCR rider revenues. Distribution deliveries increased by 3.3% in the first six months of 2014 compared to the same period of 2013. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Six Months Ended June 30 2014	2013	Increase
	(In thousands)		
Residential	28,489	27,084	5.2 %
Commercial	21,383	20,690	3.3 %
Industrial	25,461	25,119	1.4 %
Other	291	290	0.3 %
Total Electric Distribution MWH Deliveries	75,624	73,183	3.3 %

Higher deliveries to residential and commercial customers primarily reflect increased weather-related usage resulting from heating degree days that were 13% above 2013 and 14% above normal, partially offset by cooling degree days that were 7% below 2013, but 2% above normal. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical, petroleum, and paper customers.

The following table summarizes the price and volume factors contributing to the $361 million increase in generation revenues for the first six months of 2014 compared to the same period of 2013:

Source of Change in Generation Revenues	Increase (In millions)
Retail:	
Effect of increase in sales volumes	$25
Change in prices	82
	107
Wholesale:	
Effect of increase in sales volumes	140
Change in prices	114
	254
Increase in Generation Revenues	$361

The increase in retail generation sales volumes was primarily due to increased weather-related usage, as described above, partially offset by higher shopping in other jurisdictions. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 81% from 80% for the Ohio Companies and 67% from 65% for the Pennsylvania Companies and decreased to 45% from 46% for PE. The increase in retail generation prices reflects higher Pennsylvania PTC prices, the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs effective June 2013. Additionally, the impact on retail generation prices of MP's Temporary Transaction Surcharge associated with the Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs.

The increase in wholesale generation revenues of $254 million in the first six months of 2014 reflects increased energy prices associated with market conditions related to extreme weather events in January 2014 and increased volume related to the Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of net capacity.

The increase in transmission revenues of $58 million reflects higher FTR revenues at MP associated with market conditions related to extreme weather events in January 2014 and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013 as discussed above. Network transmission costs are now recovered through WP's generation rate.

Other revenues decreased $20 million primarily due to less customer requested work in the first six months of 2014 compared to the same period of 2013.

Operating Expenses —

Total operating expenses increased $388 million primarily due to the following:

- Fuel expense was $120 million higher in the first six months of 2014 primarily related to increased generation as a result of the Harrison/Pleasants asset transfer in October of 2013.

- Purchased power costs were $90 million higher primarily due to higher unit power supply costs during the first six months of 2014 compared to the same period of 2013, partially offset by a decrease in volumes required due to increased customer shopping in Ohio and Pennsylvania.

Source of Change in Purchased Power	Increase(Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 138
Change due to decreased volumes	(79)
	59
Purchases from affiliates:	
Change due to increased unit costs	34
Change due to increased volumes	5
	39
Increase in costs deferred	(8)
Increase in Purchased Power Costs	$ 90

- Other operating expenses increased $290 million primarily due to:

- Higher transmission expenses of $132 million primarily due to PJM transmission costs associated with higher congestion rates at MP as a result of market conditions related to extreme weather events in January 2014 and higher PJM transmission costs resulting from the Harrison/Pleasants asset transfer. The differences between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings,

- Higher distribution operating and maintenance expenses of $77 million primarily due to higher maintenance activities and storm-related restoration costs, including $22 million associated with Winter Storm Nika during the first quarter of 2014, of which $15 million was deferred for future recovery,

- Higher vegetation management expenses in West Virginia of $5 million, which was deferred for future recovery,

- Higher pension and OPEB costs of $19 million primarily associated with lower amortization of prior service cost credits,

- Higher energy efficiency expenses of $12 million primarily related to the Pennsylvania smart meter program implementation, which are recovered through rates, and

- Increased regulated generation operating and maintenance expenses of $28 million, reflecting increased costs associated with the Harrison/Pleasants asset transfer and a planned outage at Fort Martin.

- Depreciation expense increased $31 million due to a higher asset base, including $14 million associated with the Harrison/Pleasants asset transfer.

- Amortization (deferral) of regulatory assets decreased $142 million primarily due to higher storm cost deferrals, including $15 million related to Winter Storm Nika, lower Pennsylvania default generation service cost recovery, a reduction of NUG cost recovery at ME and PN, increased deferred vegetation management expenses in West Virginia and decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies, partially offset by the completion of marginal transmission loss refunds at ME and PN.

Other Expense —

Other expense increased $29 million in the first six months of 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million for the financing of the Harrison/Pleasants asset transfer and at JCP&L resulting from a new debt issuance of $500 million in 2013.

Income Taxes —

Regulated Distribution’s effective tax rate was 35.2% and 37.4% for the first six months of 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors and an increase in AFUDC equity flow through.

Regulated Transmission — First Six Months of 2014 Compared with First Six Months of 2013

Net income increased $12 million in the first six months of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues increased $18 million principally at ATSI and TrAIL reflecting cost of service and incremental rate base recovery resulting from their annual rate filings effective June 2013 and June 2014.

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

Revenues by Transmission Asset Owner	Six Months Ended June 30 2014	2013	Increase (Decrease)
	(In millions)		
ATSI	$109	$99	$10
TrAIL	105	94	11
PATH	6	11	(5)
Utilities	153	151	2
Total Revenues	$373	$355	$18

Operating Expenses —

Total operating expenses increased $17 million principally due to higher property taxes, depreciation and other expenses.

Other Income —

Other income increased $12 million in the first six months of 2014 compared to the same period of 2013 primarily due to higher capitalized financing costs of $22 million resulting from increased CWIP, partially offset by increased interest expense resulting from new debt issuances of $1.0 billion at FET.

Income Taxes —

Regulated Transmission’s effective tax rate was 35.2% and 37.4% for the first six months of 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors and an increase in AFUDC equity flow through.

Competitive Energy Services — First Six Months of 2014 Compared with First Six Months of 2013

Net losses decreased $220 million in the first six months of 2014, compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues increased $90 million in the first six months of 2014, compared to the same period of 2013, primarily due to increased Transmission revenue and increased sales volumes in Governmental Aggregation, Mass Market, and POLR and Structured Sales channels offset by decreased sales volumes in the Direct Sales channel. Revenues were also impacted by higher unit prices compared to 2013 as a result of increased channel pricing and ancillary pass-through revenues associated with PJM expenses incurred in January 2014, partially offset by lower prices in POLR and Structured Sales.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2014	2013	Increase (Decrease)
	(In millions)		
Direct	$1,332	$1,435	$(103)
Governmental Aggregation	597	565	32
Mass Market	242	216	26
POLR and Structured	684	633	51
Wholesale	162	158	4
Transmission	152	81	71
Other	95	86	9
Total Revenues	$3,264	$3,174	$90

MWH Sales by Channel	Six Months Ended June 30 2014	2013	Increase (Decrease)
	(In thousands)		
Direct	24,672	27,621	(10.7)%
Governmental Aggregation	10,421	10,162	2.5%
Mass Market	3,630	3,271	11.0%
POLR and Structured	14,442	12,358	16.9%
Wholesale	32	838	(96.2)%
Total MWH Sales	53,197	54,250	(1.9)%

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

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(153)	$50	$—	$—	$(103)
Governmental Aggregation	14	18	—	—	32
Mass Market	24	2	—	—	26
POLR and Structured Sales	101	(50)	—	—	51
Wholesale	(24)	—	4	24	4

The decrease in Direct revenues of $103 million resulted from lower sales volumes from commercial and industrial customers, partially offset by higher unit prices. Direct sales volumes decreased due to Competitive Energy Services' strategy to be more selective in customers targeted in response to the current market environment. The increase in Governmental Aggregation revenues of $32 million primarily reflects increased weather-related usage resulting from heating degree days that were 13% higher than the first six months of 2013 and higher unit prices. The increase in Mass Market of $26 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania, increased weather-related usage and slightly higher unit prices. The Direct, Governmental Aggregation and Mass Market customer base was 2.6 million as of June 30, 2014 compared to 2.7 million as of June 30, 2013. Higher unit prices in each of the sales channels noted above resulted from increased channel pricing. Additionally, higher Direct unit prices were impacted by approximately $33 million of ancillary pass through revenues associated with PJM expenses incurred in January 2014.

During January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including the Beaver Valley Unit 1 outage, FirstEnergy's Competitive Energy Services segment (including FES) was required to purchase higher volumes of power. These extreme weather events, which included the polar vortex, caused an increase in the demand for electricity and natural gas throughout the PJM region. In order to maintain system reliability, PJM incurred higher ancillary service costs, such as synchronous and operating reserves, throughout these extreme conditions. Approximately $800 million in ancillary service charges for the month of January 2014 were billed to all LSEs serving customers throughout the PJM region based on load served, including FES. Certain of these costs are considered a "pass-through" event under existing contracts and revenue of approximately $33 million associated with commercial and industrial customers was recognized in the first quarter of 2014.

The increase in POLR and structured sales of $51 million was due to higher POLR and structured sales volumes primarily as a result of increased weather-related usage described above. Lower structured unit prices were primarily due to market conditions related to extreme weather events in January 2014 that reduced the gains on various structured financial sales contracts, partially offset by higher POLR rates associated with recent auctions.

Wholesale revenues increased $4 million, primarily due to an increase in capacity revenue from higher capacity prices, partially offset by a decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available to sell primarily as a result of the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013.

Transmission revenue increased $71 million due to higher congestion and ancillary revenue driven by market conditions related to extreme weather events in the first quarter 2014.

Other revenue increased $9 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the first six months of 2013. Competitive Energy Services earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses increased $73 million in the first six months of 2014 due to the following:

- Fuel costs decreased $211 million primarily due to lower generation volumes resulting from the Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013 and increased outages as compared to the same period of 2013. Higher unit prices, primarily driven by increased peaking generation, was partially offset by the suspension of the DOE disposal fee, which became effective May 16, 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. In the first six months of 2014, fuel supply agreements were terminated for approximately $85 million, while settlements associated with damages on coal and transportation contracts amounted to $33 million in the first six months of 2013.
- Purchased power costs increased $675 million due to higher volumes ($439 million), increased prices ($592 million), and higher capacity expenses ($114 million), partially offset by lower losses on financially settled contracts ($470 million). Higher purchased volumes were primarily due to lower available generation due to outages, the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013. The increase in prices was primarily a result of market conditions related to extreme weather events in January 2014, partially offset by net gains on financially settled contracts. Increased customer demand that was unhedged and replacement power requirements due to the timing of unplanned outages and derates contributed to purchasing additional volumes at these higher prices. The increase in capacity expense was the result of higher capacity rates and increased sales volumes.

- Fossil operating costs decreased $63 million due primarily to lower labor costs resulting from previously deactivated units and the Harrison/Pleasants asset transfer.

- Nuclear operating costs increased $35 million as a result of higher contractor, materials and equipment costs associated with refueling outages. There were two refueling outages in the first six months of 2014 as compared to one outage in the first six months of 2013.

- Transmission expenses increased $127 million due primarily to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in January 2014, of which a portion were passed through to commercial and industrial customers, as discussed above. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.
- General taxes decreased $16 million due primarily to lower payroll taxes as a result of lower labor costs noted above, lower property taxes due to the Harrison/Pleasants asset transfer, and reduced Ohio personal property taxes.
- Impairments of long-lived assets decreased $473 million due to the impairment of two unregulated, coal-fired generating plants in the second quarter of 2013. The units were deactivated in October of 2013.
- Depreciation expense decreased $35 million primarily due to a reduction in the asset base as a result of the plant deactivations and the Harrison/Pleasants asset transfer noted above.

- Other operating expenses increased $34 million primarily due to an increase in mark-to-market expenses on commodity contract positions and an impairment of deferred advertising costs of $22 million associated with the elimination of future selling efforts in the mass market and medium commercial-industrial sales channels, partially offset by lower severance costs primarily associated with 2013 plant deactivations and retail and marketing related costs.

Other Expense —

Total other expense in the first six months of 2014 decreased $223 million compared to the same period of 2013 due to the absence of a $141 million loss on debt redemption in connection with senior notes that were repurchased in 2013, lower OTTI and higher investment income of $41 million primarily on NDT investments, and lower net interest expense of $41 million due to debt redemptions in 2013.

Income Tax Benefits —

Competitive energy services effective tax rate was 35.2% and 38.0% for the first six months of 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pretax losses, primarily resulted from changes in state apportionment factors.

Discontinued Operations —

Discontinued operations increased net income $78 million in the first six months of 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $142 million associated with the sale of hydro assets in February 2014.

Other — First Six Months of 2014 Compared with First Six Months of 2013

Financial results from other operating segments and reconciling items resulted in a $25 million increase in net income in the first six months of 2014 compared to the same period of 2013 primarily due to an increase in the benefit of AFUDC equity flow through, the elimination of certain future tax liabilities associated with basis differences, and changes in state apportionment factors. Furthermore, the 2013 effective tax rate includes the impact of recording a valuation allowance against state and local net operating loss carryforwards. Additionally, during the second quarter of 2014, FirstEnergy terminated certain interest rate swap agreements that resulted in a net benefit to interest expense of approximately $6 million. These net benefits were partially offset by increased interest expense due to the issuance of $1.5 billion of FE senior unsecured notes in March of 2013.

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of June 30, 2014 and December 31, 2013, and the changes during the six months ended June 30, 2014:

Regulatory Assets (Liabilities) by Source	June 30, 2014	December 31, 2013	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$236	$266	$(30)
Customer receivables for future income taxes	513	518	(5)
Nuclear decommissioning and spent fuel disposal costs	(224)	(198)	(26)
Asset removal costs	(360)	(362)	2
Deferred transmission costs	88	112	(24)
Deferred generation costs	324	346	(22)
Deferred distribution costs	187	194	(7)

Contract valuations	208	260	(52)
Storm-related costs	462	455	7
Other	298	263	35
Total	$1,732	$1,854	$(122)

Regulatory assets that do not earn a current return totaled approximately $468 million as of June 30, 2014 primarily related to storm damage costs.

As of June 30, 2014 and December 31, 2013, FirstEnergy had approximately $362 million and $440 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy’s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2014 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

In January 2014, FirstEnergy’s Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008. On July 15, 2014, the Board declared a dividend payable September 1, 2014 to shareholders of record at the close of business on August 7, 2014.

FirstEnergy's strategy is to focus on growth through investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion “Energizing the Future” investment plan that began in 2014 and will continue through 2017 to upgrade and expand the transmission system owned by FirstEnergy’s Regulated Transmission segment. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. FirstEnergy expects to fund these investments through a combination of debt, previously announced equity issuances through a stock investment plan and, to the extent available, employee benefit plans, and cash. In total, FirstEnergy has identified at least $7 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for growth in the years beyond 2017.

In alignment with FirstEnergy’s strategy to focus on growing the Regulated Transmission and Regulated Distribution segments and reposition the Competitive Energy Services segment, FirstEnergy is also focused on reducing balance sheet risk, maintaining investment grade metrics, and improving the business risk profile at each of its businesses. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue or refinance debt. Finally, at the competitive business, FirstEnergy completed the sale of certain hydro assets for approximately $394 million on February 12, 2014. The actions taken in 2013 and the first half of 2014, and those planned for the remainder of 2014 are expected to support a primarily regulated investment strategy.

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

As of June 30, 2014, FirstEnergy’s net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of June 30, 2014, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs [(1)]	$178
Unsecured notes	450
FMB	175
Unsecured PCRBs [(1)]	26

Collateralized lease obligation bonds	81
Sinking fund requirements	102
Other notes	4
	$1,016

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

Short-Term Borrowings

FirstEnergy had $2,323 million of short-term borrowings as of June 30, 2014, and $3,404 million as of December 31, 2013. FirstEnergy’s available liquidity as of July 31, 2014, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$3,500	$1,429
FES / AE Supply	Revolving	March 2019	1,500	1,127
FET[2]	Revolving	March 2019	1,000	1,000
		Subtotal	$6,000	$3,556
		Cash	—	107
		Total	$6,000	$3,663

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

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). 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, included in Loss on Debt Redemptions in the Consolidated Statement of Income (Loss) in the first six months of 2014.

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

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of June 30, 2014:

Borrower	FE Revolving Credit Facility Sublimit	FES/AE Supply Revolving Credit Facility Sublimit	FET Revolving Credit Facility Sublimit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)				
FE	$3,500	$—	$—	$—	(1)
FES	—	1,500	—	—	(2)
AE Supply	—	1,000	—	—	(2)
FET	—	—	1,000	—	(1)
OE	500	—	—	500	(3)
CEI	500	—	—	500	(3)
TE	500	—	—	500	(3)
JCP&L	600	—	—	850	(3)
ME	300	—	—	500	(3)
PN	300	—	—	300	(3)
WP	200	—	—	200	(3)
MP	500	—	—	500	(3)
PE	150	—	—	150	(3)
ATSI	—	—	500	500	(3)
Penn	50	—	—	50	(3)
TrAIL	—	—	400	400	(3)

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

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

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

As of June 30, 2014, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

Term Loans

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan, due December 31, 2015. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of June 30, 2014, FE was in compliance with the applicable debt to total capitalization ratios under each of these term loans.

FirstEnergy Money Pools

FirstEnergy’s utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy’s unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first six months of 2014 was 1.69% per annum for the regulated companies' money pool and 1.28% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of June 30, 2014, FirstEnergy's currently payable long-term debt included approximately $178 million ($178 million applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of June 30, 2014 were issued by the following bank:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	82	April 2015	April 2015
The Bank of Nova Scotia	96	December 2015	December 2015
Total	$178		

(1) Excludes approximately $2 million of applicable interest coverage.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of June 30, 2014:

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

On June 11, 2014, Fitch affirmed the ratings of FE and withdrew its ratings of FE subsidiary issuers.

On July 15, 2014, Moody's took the following actions:

- Upgraded the long-term ratings of six of FirstEnergy's utility subsidiaries:

ME - senior unsecured and Issuer rating to Baa1 from Baa2
MP - senior secured to A3 from Baa1
OE - senior unsecured and Issuer rating to Baa1 from Baa2; senior secured to A2 from A3
Penn - Issuer rating to Baa1 from Baa2; senior secured to A2 from A3
PE - Issuer rating to Baa2 from Baa3; senior secured to A3 from Baa1

WP - Issuer rating to Baa1 from Baa2; senior secured to A2 from A3
- Moody's also revised FirstEnergy's outlook to stable from negative and affirmed Issuer rating of Baa3.
- The Moody's outlook on all utility ratings is stable, except for JCP&L, which remains on negative outlook.

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of June 30, 2014, FE and its subsidiaries could issue additional debt of approximately $4.5 billion and remain within the limitations of the financial covenants required by the Facilities. As of June 30, 2014, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $4.5 billion given FE's consolidated debt to total capitalization ratio under its Facility.

Changes in Cash Position

As of June 30, 2014, FirstEnergy had $76 million of cash and cash equivalents compared to $218 million of cash and cash equivalents as of December 31, 2013. As of June 30, 2014 and December 31, 2013, FirstEnergy had approximately $104 million and $103 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $622 million during the first six months of 2014 compared with $493 million provided from operating activities during the first six months of 2013, as summarized in the following table:

	Six Months Ended June 30		
Operating Cash Flows	2014	2013	Increase (Decrease)
	(In millions)		
Net income	$272	$32	$240
Non-cash charges	642	1,399	(757)
Working capital and other	(292)	(938)	646
Net cash provided from operating activities	$622	$493	$129

The $757 million decrease in non-cash charges is primarily due to the following:

- a $139 million decrease in the amortization of regulatory assets as discussed above,
- a $473 million impairment of long-lived assets in 2013 resulting from the Hatfield's Ferry and Mitchell plant deactivations, and
- $133 million of a loss on debt redemptions in 2013 associated with the completion of the FES/AE Supply tender offers and FES debt redemptions.

The $646 million year over year improvement in working capital is primarily due to the following:

- Lower payments to vendors of approximately $415 million primarily resulting from payments in 2013 related to restoration costs associated with Hurricane Sandy.
- Lower tax and other payments of approximately $165 million.
- Increased customer collection of approximately $81 million.
- Make whole premiums paid during 2013 of approximately $61 million.
- Higher materials and supplies inventory of approximately $92 million.

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Cash Flows From Financing Activities

In the first six months of 2014, cash provided from financing activities was $805 million compared to $976 million of net cash provided from financing activities during the first six months of 2013. The following table summarizes new debt financing (net of any discounts) and redemptions and repurchases:

	Six Months Ended June 30	
Securities Issued or Redeemed / Repaid	2014	2013
	(In millions)	
New Issues		
PCRBs	$637	$—
Term Loan	1,050	—
Senior secured notes	—	445
Unsecured Notes	1,450	1,800
	$3,137	$2,245
Redemptions / Repayments		
PCRBs	$(682)	$(234)
Long-term revolving credit	—	(25)
Senior secured notes	(93)	(120)
Unsecured notes	(150)	(1,589)
	$(925)	$(1,968)
Tender premiums paid on debt redemptions	$—	$(110)
Short-term borrowings, net	$(1,081)	$1,285

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, included in Loss on Debt Redemptions in the Consolidated Statement of Income (Loss) in the first six months 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. The proceeds from this term loan reduced borrowings under the FE Facility.

During the first quarter of 2014, FG and NG remarketed approximately $235 million and $182 million, respectively, of PCRBs, previously held by the companies. The NG PCRBs were remarketed with a fixed interest rate of 4% per annum and a mandatory put date of June 3, 2019 and the FG PCRBs were remarketed with a fixed interest rate of 3.75% per annum and 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, respectively, of PCRBs, which were subject to a mandatory tender. The PCRBs are being held either for remarketing subject to future market and other conditions or have been remarketed in the second quarter as described below. Additionally, FG retired $50 million of PCRB's at maturity.

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 PCRBs for remarketing subject to future market and other conditions. Additionally, on April 1, 2014, ME retired $150 million of long-term debt at maturity.

During the first quarter of 2014, AE Supply returned $500 million of capital to FE Corp. Additionally, FE Corp. contributed $500 million of equity to FES.

In addition, in the second quarter of 2014, FG and NG remarketed approximately $57 million and $164 million, respectively, of PCRBs previously held by the companies. The bonds were remarketed with a fixed interest rate of 3.50% per annum with a mandatory put date of June 1, 2020.

On May 19, 2014, FET issued $600 million of 4.35% senior notes due 2025 and $400 million of 5.45% senior notes due 2044. Proceeds received from the issuance of the senior notes were used to (i) repay borrowings under its revolving credit facility and the FirstEnergy unregulated company money pool; (ii) fund a capital contribution to ATSI; and (iii) for working capital needs and other general business purposes.

On June 11, 2014, ME and PN issued $250 million of 4% senior notes due 2025 and $200 million of 4.15% senior notes due 2025, respectively. Proceeds received from the issuance of the senior notes were used to repay ME and PN's borrowings under the FirstEnergy revolving credit facility and the FirstEnergy regulated utility money pool.

Cash Flows From Investing Activities

Cash used for investing activities in the first six months of 2014 principally represented cash used for property additions. The following table summarizes investing activities for the first six months of 2014 and the comparable period of 2013:

	Six Months Ended June 30		
Cash Used for Investing Activities	2014	2013	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated distribution	$609	$719	$(110)
Regulated transmission	601	186	415
Competitive energy services	558	468	90
Other and reconciling adjustments	41	39	2
Nuclear fuel	58	50	8
Proceeds from asset sales	(394)	—	(394)
Investments	57	(4)	61
Asset removal costs	47	111	(64)
Other	(8)	1	(9)
	$1,569	$1,570	$(1)

Net cash used for investing activities during the first six months of 2014 decreased by $1 million compared to the same period of 2013.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy and its subsidiaries could be required to make under these guarantees as of June 30, 2014, was approximately $4.0 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts(1)	$214
Deferred compensation arrangements	478
Other(2)	25
	717
Subsidiaries’ Guarantees	
Energy and Energy-Related Contracts	76
LOC (long-term debt)(3)	180
FES’ guarantee of NG’s nuclear property insurance	90
FES' guarantee of NG's nuclear decommissioning costs(4)	174
FES’ guarantee of FG’s sale and leaseback obligations	1,930
Other	10
	2,460
Global Holding facility	350
Surety Bonds	464
LOCs(5)	41
	855
Total Guarantees and Other Assurances	$4,032

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

(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $17 million supporting railcar leases, and $4 million for various vehicle and equipment leases.

(3) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with maturities in 2015 and the principal amount of floating-rate PCRBs of $178 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(4) Upon acceptance by the NRC, these guarantees of $174 million, together with the guaranty of $4 million referenced in footnote (2) above by FE, replace guarantees of $136 million for nuclear decommissioning funding assurances previously provided only by FE. The increase of $38 million over the prior guarantees relates primarily to a $30 million shortfall of estimated nuclear decommissioning funding and a new guaranty of $8 million relating to spent fuel storage facilities at Beaver Valley.

(5) Includes $7 million issued for various terms pursuant to LOC capacity available under FirstEnergy’s revolving credit facilities, $12 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $22 million pledged in connection with the sale and leaseback of Perry by OE.

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

Collateral and Contingent-Related Features

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

Bilateral agreements and derivative instruments entered into by FirstEnergy and its subsidiaries have margining provisions that require posting of collateral. Based on the Competitive Energy Segments power portfolio exposures as of June 30, 2014, FES has posted collateral of $274 million and AE Supply has posted collateral of $4 million. The Regulated Distribution segment has posted collateral of $6 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations as of June 30, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$517	$6	$53	$576
BB+/Ba1 Credit Ratings	$560	$6	$53	$619
Full impact of credit contingent contractual obligations	$825	$71	$89	$985

Excluded from the preceding chart is the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of June 30, 2014, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $105 million.

Other Commitments and Contingencies

FE is a guarantor under a syndicated three-year senior secured term loan facility dated October 18, 2011, as amended, that matures October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guarantees of the obligations of Global Holding under the new facility.

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

FE, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed, most recently as of August 14, 2013, to use their best efforts to refinance the facility no later than July 20, 2015, on a non-recourse basis so that FE's guaranty can be terminated and/or released. If that refinancing does not occur, FE may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the facility in full. In lieu of providing such funding, the co-owners, at FE's option, may provide their several guaranties of Global Holding's obligations under the facility. Since January 1, 2013, FE has received a fee for providing its guaranty. The fee is payable semiannually, and accrues at a rate of 5% per annum on the average daily outstanding aggregate commitments under the facility for each semiannual period.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $1 billion as of June 30, 2014 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. As of June 30, 2014, FirstEnergy's leasehold interest was 8.11% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2. On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests representing approximately half of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term.

MARKET RISK INFORMATION

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

Commodity Price Risk

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

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 7, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of derivative contracts assets and liabilities as of June 30, 2014 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2014	2015	2016	2017	2018	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(6)	$(2)	$—	$—	$—	$—	$(8)
Other external sources[2]	2	(52)	(22)	(16)	—	—	(88)
Prices based on models	17	6	(1)	(3)	(14)	(16)	(11)
Total[3]	$13	$(48)	$(23)	$(19)	$(14)	$(16)	$(107)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $169 million in non-hedge derivative contracts related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of June 30, 2014, a 10% adverse change in commodity prices would decrease net income by approximately $24 million during the next 12 months.

Equity Price Risk

As of June 30, 2014, the FirstEnergy pension plan assets were allocated approximately as follows: 39% in equity securities, 36% in fixed income securities, 14% in absolute return strategies, 6% in real estate and 5% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. During the six months ended June 30, 2014, FirstEnergy made no contributions to its qualified pension plans. See Note 3, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. Through June 30, 2014, FirstEnergy's pension plan assets earned approximately 6.4% as compared to an annual expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG's and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of June 30, 2014, approximately 64% of the funds were invested in fixed income securities, 29% of the funds were invested in equity securities and 7% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,536 million, $700 million and $164 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2014, excluding $(36) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $70 million reduction in fair value as of June 30, 2014. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the three and six months ended June 30, 2014, $8 million in contributions were made to the NDT.

Interest Rate Risk

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year. A primary factor contributing to these actuarial gains and losses are changes in the discount rates used to value pension and OPEB obligations as of the measurement date of December 31 and the difference between expected and actual returns on the plans' assets. At this time FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 2014.

CREDIT RISK

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

Wholesale Credit Risk

FirstEnergy and FES measure wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy and FES have a legally enforceable right of set-off. FirstEnergy and FES monitor and manage the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FirstEnergy's and FES' portfolio of energy contracts has a current weighted average risk rating of A (S&P) for energy contract counterparties.

Retail Credit Risk

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

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

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

OUTLOOK

STATE REGULATION

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

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

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to 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 adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. 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. The MDPSC held a hearing on the utility reports on July 10, 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. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff. In addition, the Staff proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC has scheduled a hearing for September 15-18, 2014, to consider certain of these matters.

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.

In a 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 record in the case was closed as of June 30, 2014, and the matter is pending before the ALJ. On July 24, 2014, Rate Counsel filed a motion with the NJBPU requesting that effective August 1, 2014, JCP&L's existing rates be continued on a provisional basis until the NJBPU's final order in the base rate case and subject to refund. JCP&L filed a brief opposing the motion on August 4, 2014.

On January 23, 2013, the NJBPU opened a generic proceeding to review its policies with respect to the use of a CTA in base rate cases. The NJBPU and its Staff solicited, and were provided, input from interested stakeholders, including utilities and the Rate Counsel. On June 18, 2014, the NJBPU Staff proposed to amend current CTA policy by: 1) calculating savings using a 5 year look back from the beginning of the test year; 2) allocating savings with 75% retained by the company and 25% allocated to rate payers; and 3) excluding transmission assets of electric distribution companies in the savings calculation. Written comments on the Staff proposal are due August 18, 2014.

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) in the fourth quarter of 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. As of June 6, 2014, JCP&L has completed the required compliance filings and continues to implement the required measures directed by the above NJBPU's orders.

OHIO

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);

- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal 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.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled "Powering Ohio's Progress". The Ohio Companies have requested a decision by the PUCO by April 8, 2015. The material terms of the proposed plan include:

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

Under R.C. 4928.66 (codification of SB221), the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,200 GWHs in 2012 (an increase of 408,000 MWHs over 2011 levels), 1,705 GWHs in 2013, and 2,237 GWHs in 2014, 2015, and 2016, if an amended plan is filed as contemplated by SB310. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2014, and retain the 2014 level for 2015 and 2016 if an amended plan is filed as contemplated by SB310, and then increase the benchmark by an additional 0.75% thereafter through 2020. 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. On May 15, 2014, the Ohio Companies filed their 2013 Annual Portfolio Status Report in which they indicated compliance with 2013 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. 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.

R.C. 4928.64 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. On May 6, 2014, the PUCO issued an Entry extending the confidential treatment to February 13, 2015, of all materials and information previously granted confidential treatment.

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. The PUCO issued its Entry on Rehearing on May 21, 2014, to, among other things: 1) calculate the price to compare based on the current month's charges; and 2) allow EDUs to file for deferral authority when changing bill format.

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 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. On July 24, 2014, the PPUC unanimously approved the settlement, but voted to deny the proposal to recover NITS on a non-bypassable basis.

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 2013 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 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 recommended a penalty in the amount of $11.4 million. A prehearing conference was held on May 9, 2014 at which time the party requested, and the ALJ agreed, to stay the PPUC proceedings while the parties attempt to settle the matter. On July 30, 2014, a Joint Petition for settlement was filed, which would resolve all issues in the pending proceedings, and includes WP making a payment of $1.3 million. The settlement is subject to review and approval of the PPUC. WP's brief in the Commonwealth Court appeal proceeding is due on September 15, 2014.

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 saving 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. On June 25, 2014, the PPUC entered its Opinion and Order to approve the revised plan. The Pennsylvania Companies commenced the implementation phase of the deployment plan in July 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.

On August 4, 2014, the Pennsylvania Companies each filed tariffs with the PPUC proposing general rate increases associated with their distribution operations. The filings request approval to increase operating revenues by approximately $151.9 million at ME, $119.8 million at PN, $28.5 million at Penn, and $115.5 million at WP based upon fully projected future test years for the twelve months ending April 30, 2016 at each of the Pennsylvania Companies. The filings also propose several new cost recovery riders as well as revisions to certain existing cost recovery riders. An order on the proposed increases is expected in April 2015.

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.

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%, based on an historic 2013 test year. 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. On June 13, 2014, MP and PE amended their filing to add an additional $7.5 million of additional revenues to reimburse their expected costs of implementing monthly meter reading for residential and small commercial customers. The proposed total rate increase request, including the cost of the vegetation management program and monthly meter reading, is approximately $152 million, or 14.7%. 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. On June 25, 2014, the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from the new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines by means of a postage-stamp rate. The court also found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from them, and not based on load ratio share in PJM as a whole. The court again remanded the case back to FERC for further proceedings to implement its findings and ruling.

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. 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 the SERTP region participants' 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. On May 15, 2014, FERC issued an order denying rehearing of its March 22, 2013 order and accepting in part revisions to the PJM Operating Agreement and OATT proposed by PJM and the PJM Transmission Owners, including FirstEnergy. FERC also directed PJM and the PJM Transmission Owners to submit a further compliance filing by July 15, 2014. On May 27, 2014, FirstEnergy filed a petition for review of FERC's March 22, 2013 and May 15, 2014 orders with the U.S. Court of Appeals for the D.C. Circuit. The appeal is being held in abeyance pending the resolution of certain other appeals. Other parties' requests for rehearing of certain aspects of the May 15, 2014 order, other appeals of the March 22, 2013 and May 15, 2014 orders, and PJM's and the PJM Transmission Owners' compliance filings pursuant to the May 15, 2014 order are pending.

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 approved before ATSI joined 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. On July 18, 2014, the court denied ATSI’s petition for review, finding that FERC properly determined that the ATSI zone is responsible for an allocation of the “legacy RTEP” project costs and affirming FERC’s orders. However, the amount to be paid is pending before FERC as a result of the June 25, 2014 order from the U.S. Court of Appeals for the Seventh Circuit that is described above in the PJM Transmission Rates section. Specifically, the Seventh Circuit found that eastern PJM utilities are the primary beneficiaries of certain RTEP projects, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from them, and not based on load ratio share in PJM as a whole. The Seventh Circuit remanded the case back to FERC for further proceedings to develop a cost-allocation methodology consistent with its findings and ruling.

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 January 13, 2015. 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 and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the "joint and common market" stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June 2010, FES and AE Supply have lost more than $94 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply re-filed their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FESC, on behalf of FES and AE Supply, filed a request for rehearing of FERC's order. That request for rehearing, and all subsequent filings in the docket, are pending before FERC. The PJM stakeholders have recently begun discussing the problem of FTR underfunding again.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into four categories: (i) DR; (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. The purpose of PJM’s tariff amendments is to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. In each of the relevant dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC largely approved the tariff amendments as proposed by PJM regarding DR, imports, and transmission upgrade modeling. Compliance filings pursuant to and requests for rehearing of certain of these orders are pending before FERC. On May 9, 2014, FERC rejected the arbitrage/capacity replacement tariff amendments and ordered a technical conference to further examine the issues. The technical conference has not yet been scheduled and requests for rehearing of the May 9, 2014 order are pending before FERC.

PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM RPM capacity tariff describes the rules for calculating the “offer cap” for each unit that offers into the RPM auctions. In summary, the offer cap is calculated by identifying certain going-forward costs, including the going-forward capital requirements, for a given unit, and then subtracting the projected energy and ancillary services revenues, net of marginal costs, from the going-forward costs. The remainder becomes the offer cap. FES learned that the PJM Market Monitor’s practice for calculating the forecast energy and ancillary services revenues has been to use the lower of the unit’s economic or cost-based offers into the PJM energy market. The Market Monitor engages in this practice based on his interpretation of certain provisions of the PJM capacity tariff. However, review of the relevant tariff language suggests that only the cost-based offer data should be used. FES determined that the Market Monitor’s use of the lower of cost-based or economic offer data has the effect of suppressing the offer cap, which can distort the price signal that is intended to come out of the RPM auction process. On April 7, 2014, FES submitted a Petition for Declaratory Order to FERC, asking for an interpretation of the relevant provisions of the PJM capacity tariff. Specifically, FES identified the difference of opinion between FES and PJM and the Market Monitor regarding interpretation of the relevant provision. FES asked FERC to rule on the question of whether the tariff language permits the Market Monitor's use of the lower of cost-based or economic offer data or requires use of the cost-based offer data by May 9, 2014. On April 18, 2014, the Market Monitor and other parties filed protests to FES's petition, arguing that the PJM capacity tariff allows the Market Monitor to use market-based energy offers instead of cost-based energy offers in calculating RPM auction offer caps and asking FERC to delay action on the petition until after the May 2014 BRA. FES' petition, the protest, and related filings are pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

PJM RPM Auctions - Complaint Regarding 2014 PJM BRA

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP, just as if DR were a traditional energy resource. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC therefore lacked jurisdiction to regulate DR, such as via the PJM tariffs and programs. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was receiving a double payment (LMP plus the savings of foregone energy purchases). On July 7, 2014, FERC and other parties requested that the U.S. Court of Appeals for the D.C. Circuit grant rehearing en banc, which is a procedural path to ask the full U.S. Court of Appeals for the D.C. Circuit to reconsider the panel's decision. On July 11, 2014, FERC clarified that it is petitioning for rehearing en banc solely regarding the issue of jurisdiction, and not any other issue, including compensation and cost allocation. On August 4, 2014, and acting pursuant to a court order, the original trade group petitioners and Old Dominion Electric Cooperative filed a joint response to FERC's petition for rehearing en banc. On May 23, 2014, FESC, on behalf of FE entities with market-based rate authority, filed a complaint asking FERC to direct PJM to remove all portions of the PJM OATT, which allows or requires PJM to include DR in the PJM capacity market, and to invalidate the results of the May 2014 RPM capacity auction on the grounds that the U.S. Court of Appeals for the D.C. Circuit’s May 23, 2014 decision required removal of DR from the wholesale capacity markets. In a subsequent pleading, FESC stated its intent to file an amended complaint. FESC expects to file the amended complaint in late summer 2014. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

CAA Compliance

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

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant.

Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that AE performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, MP, PE and WP finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. On March 10, 2014, New York, Connecticut, and Maryland filed an appeal with the U.S. Court of Appeals for the Third Circuit. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to “temporarily preserve its environmental values” until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On April 29, 2014 the U.S. Supreme Court reversed the D.C Circuit decision vacating CSAPR and generally upheld the EPA's authority under the CAA to establish the regulatory structure underpinning CSAPR. Depending on the outcome of further proceedings in this matter and how the EPA and the states implement the final rules, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS was challenged in the U.S. Court of

Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. On April 15, 2014, MATS was upheld by the U.S. Court of Appeals for the D.C. Circuit, however, the Court refused to decide FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers due to a January 2013 petition for reconsideration still pending but not addressed by EPA. On July 14, 2014, various entities filed a petition seeking further review by the U.S. Supreme Court. Depending on the outcome of further appeals, if any, and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $370 million (Competitive Energy Services segment of $178 million and Regulated Distribution segment of $192 million), reduced from the previous estimate of $465 million.

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. FG intends to operate the plants through April 2015, subject to market conditions. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have agreed to pay liquidated damages for delivery shortfalls for 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FE and FES are unable to estimate the loss or range of loss.

On July 1, 2014, FES terminated a long-term fuel supply agreement. In connection with this termination, FES recognized a pre-tax charge of $67 million in the second quarter of 2014.

Climate Change

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

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as "air pollutants" under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel electric generating units. On September 20, 2013, the EPA proposed a new source performance standard, which would not apply to any existing, modified, or reconstructed fossil fuel generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. On June 2, 2014, the EPA proposed regulations to reduce CO_2 emissions from existing fossil fuel electric generating units that would require each state to develop implementation plans by June 30, 2016, to meet EPA's state specific emission rate goals. EPA's proposal allows states to request a 1-year extension for single-state implementation plans (June 30, 2017) or a 2-year extension for multi-state implementation plans (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel electric generating units. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 U.S. Court of Appeals for the D.C. Circuit decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other greenhouse gas emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by EPA to install greenhouse gas control technologies. Depending on how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. In 1997, the U.S. Senate passed the Byrd-Hagel resolution by a unanimous vote of 95-0. The resolution stated that it is the sense of the Senate that the United States should not be a signatory to any protocol to, or other agreement regarding, the United Nations Framework Convention on Climate Change which would mandate new commitments to limit or reduce GHG emissions, unless the protocol or other agreement also mandates new specific scheduled commitments to limit or reduce GHG emissions for developing country parties within the same compliance period, or would not result in serious harm to the economy of the United States. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification.

In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective. In November 2013, the U.N. Climate Change Conference in Warsaw, Poland advanced negotiations of a new global agreement to reduce GHG emissions by 2015. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

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

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. On May 19, 2014, the EPA finalized Section 316(b) regulations requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies by cooling water intake structures exceeding 125 million gallons per day. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's cooling water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

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

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013. On April 21, 2014, PA DEP recommended that the sulfate impairment designation for the Monongahela River be removed in its bi-annual water report. A 45-day public comment period ended on June 10, 2014, and PA DEP must obtain EPA approval to remove the sulfate impairment designation which would eliminate the need to develop a TMDL.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of CCRs produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of CCRs, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of CCRs. On April 19, 2013, the EPA stated it would "align" its proposed CCR regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the potential enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its ARO for LBR by $163 million in 2013. On April 3, 2014, PA DEP issued a permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizes FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCBs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, against the owner and operator of that mine, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site.

Lawsuits initially filed on October 10, 2013 and December 5, 2013, are pending against FG involving approximately 61 individuals in the U.S. District Court for the Northern District of West Virginia and approximately 26 individuals (16 of which have settled their claims) in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in the complaints, but, at this time, is unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any CCR regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of June 30, 2014 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $130 million have been accrued through June 30, 2014. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of June 30, 2014, FirstEnergy had approximately $2.4 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. By a letter dated July 2, 2014, FENOC submitted a $155 million FES parental guaranty relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry to the NRC for approval. FE and FES have also entered into a total of $23 million in parental guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. A NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft GEIC and published a proposed rule on this subject in September of 2013. On July 17, 2014, the NRC rejected a separate request to suspend the licensing decision in the Davis-Besse proceeding to allow for a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On July 25, 2014, the NRC ASLB rejected a proposed contention on the Davis-Besse shield building.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. These inspections revealed that the cracking condition has propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term CSA with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claimed their performance was excused by the force majeure clause in the CSA and presented evidence at trial that they could not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for past damages/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that defendants still owed future damages, it remanded the calculation of those damages back to the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only, and a multi-day hearing was held beginning May 13, 2014. A ruling is expected in the fourth quarter of 2014. In a related proceeding before the same court, ICG is appealing a ruling by the court that prohibited their reliance on a price re-opener clause to limit future damages.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 9, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, ASU No. 2014-09 specifies the accounting for costs to obtain or fulfill a contract with a customer and expands disclosure requirements for revenue recognition. This standard is effective for fiscal years beginning after December 15, 2016, with no early adoption permitted, and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FE. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding AE Supply and MP), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs. On February 12, 2014, FES sold its hydroelectric generation facility to LS Power and recorded a pre-tax gain of $177 million associated with the sale in the first quarter of 2014.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States. FES is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation resources in excess of committed sales, eliminate load obligations that do not adequately cover risk premiums, pursue more certain revenue streams, and modify its hedging strategy to optimize risk management and market upside opportunities. As part of this, FES has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility as was experienced in the first quarter of 2014. Going forward, FES expects to target a sales portfolio of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales, 10 to 20 million MWHs in block wholesale sales and 10 to 20 million MWHs of spot wholesale sales. Support for current customers in the channels to be exited will remain through their respective contract terms.

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

During the first quarter of 2014, FE completed a $500 million equity contribution to FES.

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

Results of Operations

Net losses increased by $5 million in the first six months of 2014 compared to the same period of 2013, as more fully described below.

Revenues -

Total revenues increased $305 million, in the first six months of 2014, compared to the same period of 2013, primarily due to increased Transmission revenue and increased sales volumes in Governmental Aggregation, Mass Market sales, and POLR and Structured Sales channels, partially offset by a decline in Direct sales. Revenues were also impacted by higher unit prices compared to 2013 as a result of increased channel pricing and ancillary pass-through revenues associated with PJM expenses incurred in January 2014.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2014	2013	Increase (Decrease)
	(In millions)		
Direct	$1,329	$1,406	$(77)
Governmental Aggregation	597	565	32
Mass Market	242	216	26
POLR and Structured	663	535	128
Wholesale	234	117	117
Transmission	134	68	66
Other	82	69	13
Total Revenues	$3,281	$2,976	$305

MWH Sales by Channel	Six Months Ended June 30 2014	2013	Increase (Decrease)
	(In thousands)		
Direct	24,622	27,130	(9.2)%
Governmental Aggregation	10,421	10,162	2.5%
Mass Market	3,630	3,271	11.0%
POLR and Structured	14,069	10,590	32.9%
Total MWH Sales	52,742	51,153	3.1%

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Financially Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(130)	$53	$—	$—	$(77)
Governmental Aggregation	14	18	—	—	32
Mass Market	24	2	—	—	26
POLR and Structured Sales	173	(45)	—	—	128
Wholesale	—	—	105	12	117

The decrease in Direct revenues of $77 million resulted from lower sales volumes from commercial and industrial customers, partially offset by higher unit prices. Direct sales volumes decreased due to FES' strategy to be more selective in customers targeted in response to the current market environment. The increase in Governmental Aggregation revenues of $32 million primarily reflects increased weather-related usage resulting from heating degree days that were 13% higher than the first six months of 2013 and higher unit prices. The increase in Mass Market of $26 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania, increased weather-related usage and higher unit prices. The Direct, Governmental Aggregation and Mass Market customer base was 2.6 million as of June 30, 2014 compared to 2.7 million as of June 30, 2013. Higher unit prices in each of the above sales channels resulted from increased channel pricing. Additionally, higher Direct unit prices were impacted by approximately $33 million of ancillary pass-through revenues associated with PJM expenses incurred in January 2014.

During January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including the Beaver Valley Unit 1 outage, FES was required to purchase higher volumes of power.

These extreme weather events, which included the polar vortex, caused an increase in the demand for electricity and natural gas throughout the PJM region. In order to maintain system reliability, PJM incurred higher ancillary service costs, such as synchronous and operating reserves, throughout these extreme conditions. Approximately $800 million in ancillary service charges for the month of January 2014 were billed to all LSEs serving customers throughout the PJM region based on load served, including FES. Certain of these costs are considered a "pass-through" event under existing contracts and revenue of approximately $33 million associated with commercial and industrial customers was recognized in the first quarter of 2014.

The increase in POLR and structured sales of $128 million was due to higher POLR and structured sales volumes primarily as a result of increased weather-related usage described above. Lower structured unit prices were primarily due to market conditions related to extreme weather events in January 2014 that reduced the gains on various structured financial sales contracts, partially offset by higher POLR rates associated with recent auctions.

Wholesale revenues increased $117 million due to higher net gains of $105 million on financially settled contracts, primarily with AE Supply, and a $12 million increase in capacity revenues. Increased gains on financially settled contracts with AE Supply resulted from higher market prices associated with extreme weather and market conditions in January 2014.

Transmission revenue increased $66 million due to higher congestion revenue associated with additional retail, POLR and Structured load and by the market conditions related to extreme weather events in the first quarter 2014.

Other revenue increased $13 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the first six months of 2013. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses increased by $660 million in the first six months of 2014 compared to the same period of 2013.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first six months of 2014 compared with the same period of 2013:

	Source of Change Increase (Decrease)				
Operating Expense	Volumes	Prices	Financially Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(23)	$28	$21	$—	$26
Nuclear Fuel	(4)	(1)	—	—	(5)
Non-affiliated Purchased Power[1]	125	843	(471)	119	616
Affiliated Purchased Power	6	1	(137)	—	(130)

[1] Realized losses on financially settled wholesale sales contracts of $337 million resulting from higher market prices were netted in purchased power and are included within Gain on Settled Contracts.

Fossil and nuclear fuel costs increased $21 million primarily due to an increase in settlement and termination costs related to coal and transportation contracts. In the first six months of 2014, a fuel supply agreement was terminated for approximately $67 million, while settlements associated with past damages on transportation contracts amounted to $46 million in the first six months of 2013. Higher fossil unit prices from increased peaking generation was partially offset by lower nuclear unit prices as a result of the suspension of the DOE disposal fee, which became effective May 16, 2014. A decrease in fossil and nuclear generation volumes due to an increase in outages in the first six months of 2014, partially offset the overall increase in prices.

Non-affiliated purchased power costs increased $616 million due to increased prices ($843 million), higher volumes ($125 million) and higher capacity expenses ($119 million), partially offset by gains on financially settled contracts

($471 million). The increase in rate was primarily a result of higher on-peak prices from market conditions related to extreme weather events in January 2014, partially offset by gains on financially settled contract hedges. Higher purchased volumes were primarily due to increased sales volume requirements, planned outages, and the timing of unplanned outages and derates during on-peak hours. The increase in capacity expense was the result of higher capacity rates and increased sales volumes.

Affiliated purchased power costs decreased $130 million primarily as a result of net gains on financially settled contracts with AE Supply.

Other operating expenses increased $154 million in the first six months of 2014, compared to the same period of 2013 primarily due to the following:

- Nuclear operating costs increased $35 million as a result of higher contractor, materials and equipment costs associated with refueling outages. There were two refueling outages in the first six months of 2014 as compared to one outage in the first six months of 2013.

- Transmission expenses increased $86 million due primarily to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in January 2014. These ancillary charges from PJM were for system reliability and a portion of which are able to be passed through to commercial and industrial customers. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.

- Other operating expenses increased $33 million primarily due to an increase in mark-to-market expenses on commodity contract positions, an impairment of deferred advertising costs associated with the elimination of future selling efforts in the mass market, medium commercial-industrial and select large commercial-industrial sales channels and, partially offset by lower leasehold costs from the Ohio Companies and retail and marketing related costs.

Other Expense -

Total other expense decreased $160 million in the first six months of 2014, compared to the same period of 2013, primarily due to the absence of a $98 million loss on debt redemptions in connection with senior notes that were repurchased, lower net interest expense of $21 million due to debt redemptions and lower OTTI and higher investment income of $41 million primarily on NDT investments.

Discontinued Operations -

Discontinued operations increased net income $109 million in the first six months of 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $177 million associated with the sale of a hydro asset described above.

Income Tax Benefits —

FES’ effective tax rates from continuing operations for the six months ended June 30, 2014 and 2013 was 39.3% and 35.6%, respectively. The increase in the effective tax rate is primarily due to an increase in pre-tax losses from continuing operations in jurisdictions with higher tax rates, a benefit resulting from a reduction in state deferred tax liabilities associated with changes in apportionment factors, partially offset by valuation allowances on local net operating loss carryforwards recognized in 2013.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

(b) Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2014, although there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FE's and FES' internal control over financial reporting, FirstEnergy completed and installed various new and upgraded information systems designed to enhance certain financial reporting and consolidation applications. These changes were intended to gain efficiencies in preparing and analyzing financial statements and were not the result of any identified deficiencies in FirstEnergy's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

During the quarter ended June 30, 2014, the following risk factors were added in addition to the risk factors included in our Annual Report or Form 10-K for the year ended December 31, 2013.

Any Denial of, or Delay in, Cost Recovery Resulting from OE’s, CEI’s and TE’s Pending ESP IV Before the PUCO May Impose Risks on our Operations and May Negatively Impact our Credit Rating, Results of Operations and Financial Condition

Electric security plans may be filed in Ohio as a means to establish the mechanism by which generation rates are set and may also include other provisions related to distribution and transmission service, all of which is subject to the approval of the PUCO. As a result, OE, CEI, and TE may not be authorized to implement all of the rates, riders, and mechanisms for which they are seeking approval, or there may be a delay in such authorization. OE, CEI, and TE filed their proposed ESP IV entitled "Powering Ohio's Progress" on August 4, 2014, which included proposals to continue their Rider DCR mechanism, base distribution rate freeze, competitive bidding process for non-shopping load, and to undertake and implement an Economic Stability Program provision designed to provide customers retail rate stability against market prices over a longer term.

There can be no assurance that OE’s, CEI’s, and TE’s request for approval of the ESP IV: "Powering Ohio's Progress" will be granted in whole or in part. OE, CEI, and TE expect to receive a decision on their ESP IV by the second quarter of 2015. Any denial of, or delay in, the approval of the ESP IV could negatively impact the results of operations and financial conditions of FE and FES.

Any Denial of, or Delay in, Cost Recovery Resulting from the Pennsylvania Companies' and MP’s and PE’s Pending Rate Cases Before the PPUC and WVPSC, Respectively, May Impose Risks on our Operations and May Negatively Impact our Credit Rating, Results of Operations and Financial Condition

Our distribution rates in Pennsylvania are set by the PPUC, and our distribution, transmission, and generation rates in West Virginia are set by the WVPSC in each case through traditional, cost-based regulated utility ratemaking. As a result, the Pennsylvania Companies, MP and PE may not be able to recover all of their increased, unexpected or necessary costs and, even if they are able to do so, there may be a significant delay between the time they incur such costs and the time they are allowed to recover them.

The Pennsylvania Companies filed their requests for base rate increases on August 4, 2014 seeking base rate increases of approximately $151.9 million for ME, $119.8 million for PN, $28.5 million for Penn, and $115.5 million for WP.

Pursuant to the written Order of the WVPSC dated October 7, 2013, MP and PE filed its base rate case petition on April 30, 2014 for approximately a $96 million increase in base rates. The case was amended on June 13, 2014 to include an additional $7.5 million related to additional costs imposed to implement monthly meter reading. The case also involves proposed cost recovery by surcharge of an additional $48 million related to a new vegetation management program approved by the WVPSC in April 2014.

There can be no assurance that either the Pennsylvania Companies’ or MP’s and PE’s requests to increase rates will be granted in whole or in part. The Pennsylvania Companies expect to receive a decision on such requests by the end of April 2015, while MP and PE expect to receive a decision on such requests by the end of February 2015. Any denial of, or delay in, their request to increase rates in the pending base rate cases or to recover their costs could negatively impact the results of operations and financial condition of FE.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

(A)	12	Fixed charge ratio
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended June 30, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

FES

(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended June 30, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

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

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

SIGNATURES

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

August 5, 2014

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

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

EXHIBIT INDEX

Exhibit Number

FirstEnergy

(A)	12	Fixed charge ratio
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
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