JERSEY CENTRAL POWER & LIGHT CO
Form 10-Q
August 07, 2012

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, 2012

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
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY (A New Jersey Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	21-0485010

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., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company

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., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company

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., Ohio Edison Company and Jersey Central Power & Light Company
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 Act).

Yes o No þ	FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company

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 AUGUST 6, 2012
FirstEnergy Corp., $.10 par value	418,216,437
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
Jersey Central Power & Light Company, $10 par value	13,628,447

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company common stock.

This combined Form 10-Q is separately filed by FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company. 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 any other registrant, except that information relating to any of the FirstEnergy subsidiary registrants is also attributed to FirstEnergy Corp.

FirstEnergy Web Site

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 FirstEnergy’s Internet web site at www.firstenergycorp.com.

These reports are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post important information on 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. Information contained on FirstEnergy’s Internet web site shall not be deemed incorporated into, or to be part of, this report.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are 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,” “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.

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry.
- 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.
- The status of the PATH project in light of PJM's direction to suspend work on the project pending review of its planning process, its re-evaluation of the need for the project and the uncertainty of the timing and amounts of any related capital expenditures.
- 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.
- Changes in markets for energy services.
- Changing energy and commodity market prices and availability.
- Financial derivative reforms that could increase our liquidity needs and collateral costs.
- The continued ability of our regulated utilities to collect transition and other costs.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water intake and coal combustion residual regulations, the potential impacts of any laws, rules or regulations that ultimately replace CAIR, including CSAPR which was stayed by the courts on December 30, 2011, and the effects of the EPA's MATS rules.
- 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 shut down or idle certain generating units).
- The uncertainties associated with our plan to deactivate our older unscrubbed regulated and competitive fossil units, including the impact on vendor commitments, and the timing of those deactivations as they relate to, among other things, the RMR arrangements and the reliability of the transmission grid.
- Issues that could result from the NRC's review of the indications of cracking in the Davis Besse Plant shield building.
- 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).
- Adverse legal decisions and outcomes related to ME's and PN's ability to recover certain transmission costs through their transmission service charge riders.
- The continuing availability of generating units, changes in their operational status and any related impacts on vendor commitments.
- Replacement power costs being higher than anticipated or inadequately hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency mandates.
- The ability to accomplish or realize anticipated benefits from strategic goals.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
- The ability to experience growth in the distribution business.
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Changing market conditions that could affect the measurement of 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 financing plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Changes in general economic conditions affecting us and our subsidiaries.
- Interest rates and any actions taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increased costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- The state of the national and regional economy and its impact on our major industrial and commercial customers.
- Issues concerning the soundness 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 annual period may in the aggregate vary from the indicated amount 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
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of AE
AGC	Allegheny Generating Company, a generation subsidiary of AE
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
Allegheny Utilities	MP, PE and WP
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
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, a subsidiary of AE, 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
FGCO	FirstEnergy Generation Corp., a subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Gunvor Group, Ltd. that owns Global Rail and Signal Peak
Global Rail	A joint venture between FEV, WMB Marketing Ventures, LLC and Gunvor Group, Ltd. 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 of AE
NGC	FirstEnergy Nuclear Generation Corp., 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 Allegheny and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland electric utility operating subsidiary of AE
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FEV, WMB Marketing Ventures, LLC and Gunvor Group, Ltd. 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 of AE

The following abbreviations and acronyms are used to identify frequently used terms in this report:

ALJ	Administrative Law Judge
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCI	Accumulated Other Comprehensive Income
AEP	American Electric Power Company, Inc.
AREPA	Alternative and Renewable Energy Portfolio Act
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board

GLOSSARY OF TERMS, Continued

BGS	Basic Generation Service
BMP	Bruce Mansfield Plant
BTU	British Thermal Units
CAA	Clean Air Act
CAL	Confirmatory Action Letter
CAIR	Clean Air Interstate Rule
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery Rider
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EHB	Environmental Hearing Board
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP	Electric Security Plan
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
ICG	International Coal Group Inc.
ILP	Integrated License Application Process
IRS	Internal Revenue Service
IT	Information Technology
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LITE	Local Infrastructure and Transmission Enhancement
LOC	Letter of Credit
LSE	Load Serving Entity

LTIP	Long-Term Incentive Plan
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midwest Independent Transmission System Operator, Inc.

GLOSSARY OF TERMS, Continued

Moody's	Moody's Investors Service, Inc.
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
NCEA	NERC Compliance Enforcement Authority
NDT	Nuclear Decommissioning Trust
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
NYSEG	New York State Electric and Gas
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection LLC
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
REC	Renewable Energy Credit
RFC	ReliabilityFirst
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
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan(s) Under the Clean Air Act

SMIP	Smart Meter Implementation Plan
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SREC	Solar Renewable Energy Credit

GLOSSARY OF TERMS, Continued

TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In millions, except per share amounts)	2012	2011	2012	2011
REVENUES:				
Electric utilities	$2,279	$2,590	$4,790	$4,925
Unregulated businesses	1,590	1,470	3,157	2,711
Total revenues*	3,869	4,060	7,947	7,636
OPERATING EXPENSES:				
Fuel	656	635	1,197	1,088
Purchased power	1,156	1,220	2,503	2,406
Other operating expenses	914	1,065	1,726	2,058
Provision for depreciation	292	287	577	512
Amortization of regulatory assets, net	62	90	137	222
General taxes	232	242	504	479
Total operating expenses	3,312	3,539	6,644	6,765
OPERATING INCOME	557	521	1,303	871
OTHER INCOME (EXPENSE):				
Investment income	13	31	24	52
Interest expense	(274)	(265)	(520)	(496)
Capitalized interest	19	20	36	38
Total other expense	(242)	(214)	(460)	(406)
INCOME BEFORE INCOME TAXES	315	307	843	465
INCOME TAXES	127	114	349	225
NET INCOME	188	193	494	240
Income (loss) attributable to noncontrolling interest	1	(10)	1	(15)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$187	$203	$493	$255
EARNINGS PER SHARE OF COMMON STOCK:				
Basic	$0.45	$0.48	$1.18	$0.67
Diluted	$0.45	$0.48	$1.18	$0.67
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	417	418	418	380
Diluted	419	420	419	382
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$—	$—	$0.55	$0.55

* Includes excise tax collections of $107 million and $116 million in the three months ended June 30, 2012 and 2011, respectively, and $228 million and $235 million in the six months ended June 30, 2012 and 2011, respectively.

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
NET INCOME	$188	$193	$494	$240
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(48)	48	(101)	4
Amortized losses on derivative hedges	3	17	1	11
Change in unrealized gain on available-for-sale securities	2	10	12	19
Other comprehensive income (loss)	(43)	75	(88)	34
Income taxes (benefits) on other comprehensive income (loss)	(27)	33	(51)	14
Other comprehensive income (loss), net of tax	(16)	42	(37)	20
COMPREHENSIVE INCOME	172	235	457	260
Comprehensive income (loss) attributable to noncontrolling interest	1	(10)	1	(15)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$171	$245	$456	$275

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, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$94	$202
Receivables-		
Customers, net of allowance for uncollectible accounts of $36 in 2012 and $37 in 2011	1,635	1,525
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	263	269
Materials and supplies	921	811
Prepaid taxes	248	191
Derivatives	276	235
Other	171	122
	3,608	3,355
PROPERTY, PLANT AND EQUIPMENT:		
In service	41,167	40,122
Less — Accumulated provision for depreciation	12,336	11,839
	28,831	28,283
Construction work in progress	1,937	2,054
	30,768	30,337
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,153	2,112
Investments in lease obligation bonds	326	402
Other	1,039	1,008
	3,518	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,444	6,441
Regulatory assets	2,122	2,030
Other	1,588	1,641
	10,154	10,112
	$48,048	$47,326
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,577	$1,621
Short-term borrowings	1,890	—
Accounts payable	1,052	1,174
Accrued taxes	436	558
Accrued compensation and benefits	288	384
Derivatives	222	218
Other	617	900
	6,082	4,855
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 418,216,437 shares outstanding	42	42
Other paid-in capital	9,756	9,765

Accumulated other comprehensive income	389	426
Retained earnings	3,310	3,047
Total common stockholders' equity	13,497	13,280
Noncontrolling interest	15	19
Total equity	13,512	13,299
Long-term debt and other long-term obligations	15,159	15,716
	28,671	29,015
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,042	5,670
Retirement benefits	2,257	2,823
Asset retirement obligations	1,548	1,497
Deferred gain on sale and leaseback transaction	909	925
Adverse power contract liability	559	469
Other	1,980	2,072
	13,295	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$48,048	$47,326

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30	
(In millions)	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$494	$240
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	577	512
Amortization of regulatory assets, net	137	222
Nuclear fuel and lease amortization	106	92
Deferred purchased power and other costs	(149)	(168)
Deferred income taxes and investment tax credits, net	423	598
Deferred rents and lease market valuation liability	(106)	(61)
Stock based compensation	(18)	(4)
Accrued compensation and retirement benefits	(160)	(31)
Commodity derivative transactions, net	(86)	(21)
Pension trust contributions	(600)	(262)
Asset impairments	7	41
Cash collateral, net	22	(31)
Decrease (increase) in operating assets-		
Receivables	(105)	199
Materials and supplies	(109)	24
Prepayments and other current assets	(117)	(268)
Decrease in operating liabilities-		
Accounts payable	(122)	(28)
Accrued taxes	(192)	(66)
Accrued interest	(5)	(4)
Other	65	47
Net cash provided from operating activities	62	1,031
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	182	503
Short-term borrowings, net	1,890	—
Redemptions and Repayments-		
Long-term debt	(746)	(1,002)
Short-term borrowings, net	—	(44)
Common stock dividend payments	(460)	(420)
Other	(35)	(76)
Net cash provided from (used for) financing activities	831	(1,039)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,001)	(1,018)
Sales of investment securities held in trusts	382	1,703
Purchases of investment securities held in trusts	(420)	(1,807)
Cash investments	87	50
Cash received in Allegheny merger	—	590

Other	(49)	(53)
Net cash used for investing activities	(1,001)	(535)
Net change in cash and cash equivalents	(108)	(543)
Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	$94	$476
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction: merger with Allegheny, common stock issued	$—	$4,354

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

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

	Three Months Ended June 30		Six Months Ended June 30	
(In millions)	2012	2011	2012	2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales to non-affiliates	$1,293	$1,052	$2,625	$2,097
Electric sales to affiliates	109	170	230	431
Other	54	70	117	156
Total revenues	1,456	1,292	2,972	2,684
OPERATING EXPENSES:				
Fuel	380	316	675	659
Purchased power from affiliates	133	65	250	134
Purchased power from non-affiliates	434	329	921	626
Other operating expenses	393	413	688	878
Provision for depreciation	69	69	132	138
General taxes	32	30	69	60
Impairment of long-lived assets	—	7	—	20
Total operating expenses	1,441	1,229	2,735	2,515
OPERATING INCOME	15	63	237	169
OTHER INCOME (EXPENSE):				
Investment income	6	16	12	22
Miscellaneous income	20	4	24	8
Interest expense — affiliates	(2)	(2)	(4)	(3)
Interest expense — other	(48)	(52)	(89)	(105)
Capitalized interest	9	10	18	20
Total other expense	(15)	(24)	(39)	(58)
INCOME BEFORE INCOME TAXES	—	39	198	111
INCOME TAXES	1	10	77	37
NET INCOME (LOSS)	$(1)	$29	$121	$74
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME (LOSS)	$(1)	$29	$121	$74
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	8	(5)	3	(9)
Amortized gain (loss) on derivative hedges	1	14	(4)	5
Change in unrealized gain on available-for-sale securities	3	8	13	15
Other comprehensive income	12	17	12	11
Income taxes on other comprehensive income	2	8	4	4

Other comprehensive income, net of tax	10	9	8	7
COMPREHENSIVE INCOME	$9	$38	$129	$81

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$7	$7
Receivables-		
Customers, net of allowance for uncollectible accounts of $16 in 2012 and 2011	457	424
Affiliated companies	537	600
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	96	61
Notes receivable from affiliated companies	228	383
Materials and supplies	548	492
Derivatives	265	219
Prepayments and other	19	38
	2,157	2,224
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,375	10,983
Less — Accumulated provision for depreciation	4,314	4,110
	7,061	6,873
Construction work in progress	919	1,014
	7,980	7,887
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,250	1,223
Other	7	7
	1,257	1,230
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	118	123
Goodwill	24	24
Property taxes	43	43
Unamortized sale and leaseback costs	118	80
Derivatives	110	79
Other	137	129
	550	478
	$11,944	$11,819
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,144	$905
Accounts payable-		
Affiliated companies	608	436
Other	306	220
Accrued taxes	62	227
Derivatives	219	189
Other	242	261
	2,581	2,238
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,568	1,570

Accumulated other comprehensive income	84	76
Retained earnings	2,052	1,931
Total common stockholder's equity	3,704	3,577
Long-term debt and other long-term obligations	2,500	2,799
	6,204	6,376
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	909	925
Accumulated deferred income taxes	436	286
Asset retirement obligations	934	904
Retirement benefits	179	356
Lease market valuation liability	148	171
Other	553	563
	3,159	3,205
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$11,944	$11,819

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 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$121	$74
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	132	138
Nuclear fuel and lease amortization	103	92
Deferred rents and lease market valuation liability	(103)	(58)
Deferred income taxes and investment tax credits, net	162	138
Asset impairments	6	28
Gain on asset sales	(17)	—
Accrued compensation and retirement benefits	14	(24)
Pension trust contribution	(209)	—
Commodity derivative transactions, net	(53)	(60)
Cash collateral, net	17	(40)
Decrease (increase) in operating assets-		
Receivables	—	(36)
Materials and supplies	(56)	50
Prepayments and other current assets	19	12
Increase (decrease) in operating liabilities-		
Accounts payable	243	(124)
Accrued taxes	(167)	(29)
Other	7	21
Net cash provided from operating activities	219	182
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	82	247
Short-term borrowings, net	—	530
Redemptions and repayments-		
Long-term debt	(140)	(472)
Other	(6)	(11)
Net cash provided from (used for) financing activities	(64)	294
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(303)	(334)
Proceeds from assets sale	17	—
Sales of investment securities held in trusts	109	513
Purchases of investment securities held in trusts	(127)	(545)
Loans to affiliated companies, net	155	(93)
Other	(6)	(20)
Net cash used for investing activities	(155)	(479)
Net change in cash and cash equivalents	—	(3)

Cash and cash equivalents at beginning of period	7	9
Cash and cash equivalents at end of period	$7	$6

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

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$364	$360	$723	$724
Excise and gross receipts tax collections	24	25	51	53
Total revenues	388	385	774	777
OPERATING EXPENSES:				
Purchased power from affiliates	38	69	90	163
Purchased power from non-affiliates	66	63	136	123
Other operating expenses	119	106	240	202
Provision for depreciation	25	23	49	46
Amortization of regulatory assets, net	15	2	15	3
General taxes	46	46	96	95
Total operating expenses	309	309	626	632
OPERATING INCOME	79	76	148	145
OTHER INCOME (EXPENSE):				
Investment income	5	4	9	9
Interest expense	(23)	(22)	(45)	(44)
Capitalized interest	1	1	2	1
Total other expense	(17)	(17)	(34)	(34)
INCOME BEFORE INCOME TAXES	62	59	114	111
INCOME TAXES	21	18	42	38
NET INCOME	$41	$41	$72	$73
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$41	$41	$72	$73
OTHER COMPREHENSIVE LOSS:				
Pensions and OPEB prior service costs	(7)	(7)	(17)	(15)
Change in unrealized gain on available-for-sale securities	—	2	—	2
Other comprehensive loss	(7)	(5)	(17)	(13)
Income tax benefits on other comprehensive loss	(4)	(3)	(9)	(7)
Other comprehensive loss, net of tax	(3)	(2)	(8)	(6)
COMPREHENSIVE INCOME	$38	$39	$64	$67

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

OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$—	$26
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2012 and 2011	173	163
Affiliated companies	51	86
Other	15	41
Notes receivable from affiliated companies	245	181
Prepayments and other	14	17
	498	514
UTILITY PLANT:		
In service	3,443	3,358
Less — Accumulated provision for depreciation	1,294	1,267
	2,149	2,091
Construction work in progress	87	91
	2,236	2,182
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	148	163
Nuclear plant decommissioning trusts	141	137
Other	91	90
	380	390
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	340	363
Property taxes	80	81
Unamortized sale and leaseback costs	23	25
Other	23	19
	466	488
	$3,580	$3,574
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$3	$2
Accounts payable-		
Affiliated companies	90	119
Other	37	35
Accrued taxes	76	88
Accrued interest	28	25
Other	69	79
	303	348
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 175,000,000 shares – 60 shares outstanding	721	747
Accumulated other comprehensive income	46	54
Accumulated deficit	(12)	(84)

Total common stockholder's equity	755	717
Noncontrolling interest	5	5
Total equity	760	722
Long-term debt and other long-term obligations	1,157	1,155
	1,917	1,877
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	799	787
Retirement benefits	211	213
Asset retirement obligations	74	71
Other	276	278
	1,360	1,349
COMMITMENTS AND CONTINGENCIES (Note 9)		
	$3,580	$3,574

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30	
(In millions)	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$72	$73
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	49	46
Amortization of regulatory assets, net	15	3
Amortization of lease costs	(5)	(5)
Deferred income taxes and investment tax credits, net	22	66
Accrued compensation and retirement benefits	(26)	(18)
Pension trust contribution	—	(27)
Decrease (increase) in operating assets-		
Receivables	54	81
Prepayments and other current assets	3	(29)
Decrease in operating liabilities-		
Accounts payable	(27)	(22)
Accrued taxes	(12)	(9)
Accrued interest	3	—
Other	(2)	(9)
Net cash provided from operating activities	146	150
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(1)	(1)
Short-term borrowings, net	—	(142)
Common stock dividend payments	(25)	(268)
Other	(1)	(2)
Net cash used for financing activities	(27)	(413)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(86)	(79)
Sales of investment securities held in trusts	57	20
Purchases of investment securities held in trusts	(62)	(25)
Loans to affiliated companies, net	(63)	(79)
Cash investments	13	12
Other	(4)	(6)
Net cash used for investing activities	(145)	(157)
Net change in cash and cash equivalents	(26)	(420)
Cash and cash equivalents at beginning of period	26	420
Cash and cash equivalents at end of period	$—	$—

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In millions)	2012	2011	2012	2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$476	$577	$954	$1,211
Excise tax collections	8	11	18	24
Total revenues	484	588	972	1,235
OPERATING EXPENSES:				
Purchased power	254	328	518	698
Other operating expenses	81	73	162	153
Provision for depreciation	32	28	62	54
Amortization of regulatory assets, net	8	40	28	122
General taxes	12	15	27	33
Total operating expenses	387	484	797	1,060
OPERATING INCOME	97	104	175	175
OTHER INCOME (EXPENSE):				
Miscellaneous income	1	3	2	5
Interest expense	(30)	(31)	(61)	(61)
Capitalized interest	1	1	1	1
Total other expense	(28)	(27)	(58)	(55)
INCOME BEFORE INCOME TAXES	69	77	117	120
INCOME TAXES	30	32	52	52
NET INCOME	$39	$45	$65	$68
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$39	$45	$65	$68
OTHER COMPREHENSIVE LOSS:				
Pensions and OPEB prior service costs	(6)	(6)	(12)	(12)
Other comprehensive loss	(6)	(6)	(12)	(12)
Income tax benefits on other comprehensive loss	(3)	(3)	(7)	(5)
Other comprehensive loss, net of tax	(3)	(3)	(5)	(7)
COMPREHENSIVE INCOME	$36	$42	$60	$61

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

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JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Receivables-		
Customers, net of allowance for uncollectible accounts of $3 in 2012 and 2011	$227	$235
Affiliated companies	12	—
Other	23	17
Prepaid taxes	108	33
Other	22	19
	392	304
UTILITY PLANT:		
In service	5,067	4,872
Less — Accumulated provision for depreciation	1,779	1,743
	3,288	3,129
Construction work in progress	125	227
	3,413	3,356
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	227	219
Nuclear plant decommissioning trusts	196	193
Other	2	2
	425	414
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	523	408
Other	33	32
	2,367	2,251
	$6,597	$6,325
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$35	$34
Short-term borrowings-		
Affiliated companies	338	259
Other	80	—
Accounts payable-		
Affiliated companies	16	19
Other	101	101
Accrued compensation and benefits	33	41
Customer deposits	24	24
Accrued interest	18	18
Other	21	36
	666	532
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, $10 par value, authorized 16,000,000 shares, 13,628,447 shares outstanding	136	136

Other paid-in capital	2,011	2,011
Accumulated other comprehensive income	34	39
Retained earnings	136	121
Total common stockholder's equity	2,317	2,307
Long-term debt and other long-term obligations	1,720	1,736
	4,037	4,043
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	917	859
Power purchase contract liability	270	147
Nuclear fuel disposal costs	197	197
Retirement benefits	163	170
Asset retirement obligations	119	115
Other	228	262
	1,894	1,750
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 9)		
	$6,597	$6,325

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

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JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$65	$68
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	62	54
Amortization of regulatory assets, net	28	122
Deferred purchased power and other costs	(75)	(71)
Deferred income taxes and investment tax credits, net	64	55
Accrued compensation and retirement benefits	(27)	(11)
Pension trust contribution	—	(105)
Decrease (increase) in operating assets-		
Receivables	(10)	58
Prepaid taxes	(75)	(125)
Increase (decrease) in operating liabilities-		
Accounts payable	(2)	14
Accrued taxes	(14)	(1)
Other	7	—
Net cash provided from operating activities	23	58
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	159	411
Redemptions and Repayments-		
Long-term debt	(16)	(15)
Common stock dividend payments	(50)	(500)
Other	—	(1)
Net cash provided from (used for) financing activities	93	(105)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(102)	(98)
Loans to affiliated companies, net	—	161
Sales of investment securities held in trusts	165	376
Purchases of investment securities held in trusts	(172)	(386)
Other	(7)	(6)
Net cash provided from (used for) investing activities	(116)	47
Net change in cash and cash equivalents	—	—
Cash and cash equivalents at beginning of period	—	—
Cash and cash equivalents at end of period	$—	$—

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.

FE is a diversified energy holding company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FENOC, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP and FET), FES and its principal subsidiaries (FGCO and NGC), and FESC. AE merged with a subsidiary of FirstEnergy on February 25, 2011, with AE continuing as the surviving corporation and becoming a wholly owned subsidiary of FirstEnergy. Accordingly, consolidated results of operations for the six months ended June 30, 2011, include just four months of Allegheny results.

The consolidated financial statements of FE, FES, OE and JCP&L include the accounts of entities in which a controlling financial interest is held, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% or the result of an analysis that identifies FE or one of its subsidiaries as the primary beneficiary of a VIE. Investments in which a controlling financial interest is not held are accounted for under the equity or cost method of accounting.

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, 2011.

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 presentation 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.

As described in its Annual Report on Form 10-K for the year ended December 31, 2011, FE's consolidated financial statements for the six months ended June 30, 2011, were revised to reflect a purchase accounting measurement adjustment identified during the fourth quarter of 2011 that decreased goodwill and increased income tax expense by approximately $20 million.

As described in its Annual Report on Form 10-K for the year ended December 31, 2011, during the fourth quarter of 2011, FE elected to change its method of accounting relating to its defined benefit pension and OPEB plans to recognize the change in fair value of plan assets and net actuarial gains and losses immediately, and applied this change retrospectively. Generally, these gains and losses are measured annually as of December 31, and accordingly, will be recorded during the fourth quarter.

Certain prior year amounts have been reclassified to conform to the current year presentation.

New Accounting Pronouncements

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

2. EARNINGS PER SHARE

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

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	Three Months Ended June 30 2012	2011	Six Months Ended June 30 2012	2011
	(In millions, except per share amounts)			
Weighted average number of basic shares outstanding	417	418	418	380
Assumed exercise of dilutive stock options and awards[1]	2	2	1	2
Weighted average number of diluted shares outstanding	419	420	419	382
Earnings Available to FirstEnergy Corp.	$187	$203	$493	$255
Basic earnings per share of common stock	$0.45	$0.48	$1.18	$0.67
Diluted earnings per share of common stock	$0.45	$0.48	$1.18	$0.67

(1) The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect were not significant for the three months and six months ended June 30, 2012 and 2011.

3. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pensions and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the six months ended June 30, 2012, FirstEnergy made a voluntary $600 million pre-tax contribution to its qualified pension plan.

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

Components of Net Periodic Benefit Costs (Credits) For the Three Months Ended June 30,	Pensions 2012	2011	OPEB 2012	2011
	(In millions)			
Service cost	$40	$34	$3	$3
Interest cost	97	96	12	12
Expected return on plan assets	(121)	(115)	(9)	(10)
Amortization of prior service cost	3	4	(51)	(51)
Other adjustments (settlements, curtailments, etc)	—	—	—	—
Net periodic costs (credits)	$19	$19	$(45)	$(46)

Components of Net Periodic Benefit Costs (Credits) For the Six Months Ended June 30,	Pensions 2012	2011	OPEB 2012	2011
	(In millions)			
Service cost	$80	$63	$6	$6
Interest cost	194	180	24	23
Expected return on plan assets	(242)	(217)	(18)	(20)
Amortization of prior service cost	6	8	(102)	(99)
Other adjustments (settlements, curtailments, etc)	—	7	—	—

Net periodic costs (credits)	$38	$41	$(90)	$(90)

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 its subsidiaries were as follows:

Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Three Months Ended June 30,	2012	2011	2012	2011
	(In millions)			
FE Consolidated	$14	$14	$(32)	$(34)
FES	11	7	(8)	(9)
OE	(1)	(2)	(6)	(5)
JCP&L	(2)	(3)	(2)	(2)

Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Six Months Ended June 30,	2012	2011	2012	2011
	(In millions)			
FE Consolidated	$27	$34	$(62)	$(66)
FES	21	14	(16)	(16)
OE	(2)	(4)	(11)	(11)
JCP&L	(3)	(5)	(4)	(5)

4. INCOME TAXES

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. During the second quarter of 2012, FirstEnergy reached a settlement with state authorities related to state apportionment factors in Pennsylvania on an intercompany asset sale, which favorably affected FirstEnergy's effective tax rate by $3 million in the three and six months ended June 30, 2012. Earlier in the year, the federal government issued further guidance related to the tax accounting of costs to repair and maintain fixed assets. This guidance provided a safe harbor method of tax accounting for the AE companies and allowed these companies to reduce their amount of unrecognized tax benefits by $21 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, with no resulting impact to FirstEnergy's effective tax rate for the first six months of 2012. In the second quarter of 2011, FirstEnergy reached a settlement with the IRS on a research and development claim and recognized approximately $30 million of income tax benefits, including $5 million that favorably affected FirstEnergy's effective tax rate in the three and six months ended June 30, 2011.

As of June 30, 2012, it is reasonably possible that approximately $42 million of unrecognized income tax benefits may be resolved within the next twelve months, of which approximately $7 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized income tax benefits is primarily associated with issues related to the capitalization of certain costs and various state tax items.

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. During the first six months of 2012 there were no material changes to the amount of accrued interest. The interest associated with the settlement of the claim in 2011 noted above favorably affected FirstEnergy's effective tax rate by $6 million in the first six months of 2011. During the first six months of 2011, there were no other material changes to the amount of accrued interest, except for a $6 million increase in accrued interest from the merger with AE in the first quarter of 2011. The net amount of interest accrued as of June 30, 2012 was $12 million, compared with $11 million as of December 31, 2011.

As a result of the non-deductible portion of merger transaction costs, FirstEnergy's effective tax rate was unfavorably impacted by $28 million in the first six months of 2011.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2010) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2008-2010, and additionally 2005-2007 for New Jersey. The IRS completed its audits of tax year 2008 in July 2010 and tax year 2009 in April 2011, with both tax years having one open item. Tax years 2010-2011 are under review by the IRS. Allegheny is currently under audit by the IRS for tax years 2009 and 2010. State tax returns for tax years 2008 through 2010 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy's financial condition, results of operations, cash flow or liquidity.

5. 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. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy's consolidated financial statements for the second quarter of 2012 are: the PNBV and Shippingport capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and JCP&L's supply of BGS, of which $262 million was outstanding as of June 30, 2012; and special purpose limited liabilities companies of MP and PE created to issue environmental control bonds that were used to construct environmental control facilities, of which $503 million was outstanding as of June 30, 2012.

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, 2012, was primarily due to net income attributable to noncontrolling interests of $1 million, offset by a $5 million distribution to owners.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregated variable interests into the following categories based on similar risk characteristics and significance.

Mining Operations

On October 18, 2011, a subsidiary of Gunvor Group, Ltd. purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. FEV retained a 33-1/3% equity ownership in the joint venture. Prior to the sale, FirstEnergy consolidated this joint venture since FEV was determined to be the primary beneficiary of the VIE. As a result of the sale, FEV was no longer determined to be the primary beneficiary and its retained 33-1/3% interest is subsequently accounted for using the equity method of accounting.

PATH-WV

PATH was formed to construct, through its operating companies, the PATH Project, which is a high-voltage transmission line that was proposed to extend from West Virginia through Virginia and into Maryland, including 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 as directed by PJM. 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 AE 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 to be constructed by PATH-WV. Because of the nature of PATH-WV's operations and its FERC approved rate mechanism, FirstEnergy's maximum exposure to loss, through AE, consists of its equity investment in PATH-WV, which was $31 million as of June 30, 2012.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities if the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, ME, PN, PE, WP and MP, maintains 21 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, these entities.

FirstEnergy has determined that for all but three of these NUG entities, its subsidiaries do not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. JCP&L, PE and WP may hold variable interests in the remaining three entities; however, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities. One of JCP&L's NUG contracts, to which the scope exception was applied, expired during 2011.

Because JCP&L, PE and WP have no equity or debt interests in the NUG entities, their maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred by its subsidiaries to be recovered from customers, except as described further below. Purchased power costs related to the three contracts that may contain a variable interest that were held by FirstEnergy subsidiaries during the three months ended June 30, 2012, were $14 million, $27 million and $17 million for JCP&L, PE and WP, respectively and $26 million, $59 million and $33 million for the six months ended June 30, 2012, respectively. Purchased power costs related to the four contracts that may contain a variable interest that were held by JCP&L, PE and WP, respectively, during the three months ended June 30, 2011, were $55 million, $47 million, and $21 million, respectively and $120 million, $58 million and $26 million for the six months ended June 30, 2011, respectively.

In 1998 the PPUC issued an order approving a transition plan for WP that disallowed certain costs, including an estimated amount for an adverse power purchase commitment related to the NUG entity wherein WP may hold a variable interest, for which WP has taken the scope exception. As of June 30, 2012, WP's reserve for this adverse purchase power commitment was $48 million, including a current liability of $11 million, and is being amortized over the life of the commitment.

Loss Contingencies

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 arrangement. FES, OE 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 mentioned above as of June 30, 2012:

	Maximum Exposure	Discounted Lease Payments, net[(1)]	Net Exposure
	(In millions)		
FES	$1,318	$1,111	$207
OE	574	384	190
Other FE subsidiaries	599	333	266

(1) The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.5 billion.

6. FAIR VALUE MEASUREMENTS

RECURRING AND NONRECURRING FAIR VALUE MEASUREMENTS

On January 1, 2012, FirstEnergy adopted an amendment to the authoritative accounting guidance regarding fair value measurements. The amendment was applied prospectively and expanded disclosure requirements for fair value measurements, particularly for Level 3 measurements, among other changes.

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 for Level 2 and Level 3 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 the 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 subsequently adjusted to fair value using a mark-to-model methodology on a monthly basis, which approximates market. The primary inputs into the model, that are generally less observable from 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 7, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchased 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 using a mark-to-model methodology on a quarterly basis, 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 IntercontinentalExchange 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 using a mark-to-model methodology on a quarterly basis, which approximates market. The primary unobservable input into the model is forecasted regional capacity prices. Quarterly pricing for the LCAPP contracts is a combination of PJM RPM capacity auction prices for the 2015/2016 delivery year and internal models using historical trends and market data for the remaining years under contract. Capacity prices beyond the 2015/2016 delivery year are developed through a simulation of future PJM RPM auctions. The capacity price forecast assumes a continuation of the current PJM RPM market design and is reflective of the regional peak demand growth and generation fleet additions and retirements that underlie FirstEnergy’s long-term energy price forecast. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of June 30, 2012 from those used as of December 31, 2011. 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, 2012. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy.

FE CONSOLIDATED

Recurring Fair Value Measurements	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,636	$—	1,636	$—	$1,544	$—	$1,544
Derivative assets - commodity contracts	4	337	—	341	—	264	—	264
Derivative assets - FTRs	—	—	12	12	—	—	1	1
Derivative assets - interest rate swaps	—	3	—	3	—	—	—	—
Derivative assets - NUG contracts(1)	—	—	9	9	—	—	56	56
Equity securities(2)	280	—	—	280	259	—	—	259
Foreign government debt securities	—	—	—	—	—	3	—	3
U.S. government debt securities	—	144	—	144	—	148	—	148
U.S. state debt securities	—	308	—	308	—	314	—	314
Other(3)	63	128	—	191	49	225	—	274
Total assets	347	2,556	21	2,924	308	2,498	57	2,863
Liabilities								
Derivative liabilities - commodity contracts	(1)	(262)	—	(263)	—	(247)	—	(247)
Derivative liabilities - FTRs	—	—	(9)	(9)	—	—	(23)	(23)
Derivative liabilities - interest rate swaps	—	(23)	—	(23)	—	—	—	—
Derivative liabilities - NUG contracts(1)	—	—	(302)	(302)	—	—	(349)	(349)
Derivative liabilities - LCAPP contracts(1)	—	—	(145)	(145)	—	—	—	—
Total liabilities	(1)	(285)	(456)	(742)	—	(247)	(372)	(619)
Net assets (liabilities)(4)	$346	$2,271	$(435)	$2,182	$308	$2,251	$(315)	$2,244

(1) NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $(7) million and $(52) million as of June 30, 2012 and December 31, 2011, 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 and LCAPP contracts held by certain Utilities and FTRs held by FirstEnergy and classified as Level 3 in the fair value hierarchy for the periods ended June 30, 2012 and December 31, 2011:

	NUG Contracts(1)			LCAPP Contracts(1)			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
January 1, 2011 Balance	$122	$(466)	$(344)	$—	$—	$—	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—	—	—	—
Unrealized gain (loss)	(58)	(144)	(202)	—	—	—	2	(27)	(25)
Purchases	—	—	—	—	—	—	13	(4)	9
Issuances	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	(7)	261	254	—	—	—	(14)	20	6
Transfers in (out) of Level 3	—	—	—	—	—	—	—	(12)	(12)
December 31, 2011 Balance	$57	$(349)	$(292)	$—	$—	$—	$1	$(23)	$(22)
Realized gain (loss)	—	—	—	—	—	—	—	—	—
Unrealized gain (loss)	(48)	(86)	(134)	—	—	—	—	(2)	(2)
Purchases	—	—	—	—	(145)	(145)	12	(9)	3
Issues	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	—	133	133	—	—	—	(1)	25	24
Transfers in (out) of Level 3	—	—	—	—	—	—	—	—	—
June 30, 2012 Balance	$9	$(302)	$(293)	$—	$(145)	$(145)	$12	$(9)	$3

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

Level 3 Quantitative Information

The following table provides quantitative information for FTRs, NUG contracts and LCAPP contracts that are classified as Level 3 in the fair value hierarchy for the period ended June 30, 2012:

	Fair Value as of June 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$3	Model	RTO auction clearing prices	($3.60) to $4.90	$0.70	Dollars/MWH
NUG Contracts	$(293)	Model	Generation Electricity regional prices	500 to 6,609,000 $49.50 to $84.90	2,665,000 $63.70	MWH Dollars/MWH
LCAPP Contracts	$(145)	Model	Regional capacity prices	$94.90 to $248.40	$183.90	Dollars/MW-Day

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FES

Recurring Fair Value Measurements	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,057	$—	$1,057	$—	$1,010	$—	$1,010
Derivative assets - commodity contracts	4	326	—	330	—	248	—	248
Derivative assets - FTRs	—	—	8	8	—	—	1	1
Equity securities(1)	145	—	—	145	124	—	—	124
Foreign government debt securities	—	—	—	—	—	3	—	3
U.S. government debt securities	—	6	—	6	—	7	—	7
U.S. state debt securities	—	—	—	—	—	5	—	5
Other(2)	—	48	—	48	—	132	—	132
Total assets	149	1,437	8	1,594	124	1,405	1	1,530
Liabilities								
Derivative liabilities - commodity contracts	(1)	(262)	—	(263)	—	(234)	—	(234)
Derivative liabilities - FTRs	—	—	(6)	(6)	—	—	(7)	(7)
Total liabilities	(1)	(262)	(6)	(269)	—	(234)	(7)	(241)
Net assets (liabilities)(3)	$148	$1,175	$2	$1,325	$124	$1,171	$(6)	$1,289

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

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

(3) Excludes $(6) million and $(58) million as of June 30, 2012 and December 31, 2011, 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, 2012 and December 31, 2011:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
	(In millions)		
January 1, 2011 Balance	$—	$—	$—
Realized gain (loss)	—	—	—
Unrealized gain (loss)	4	(8)	(4)
Purchases	2	(1)	1
Issuances	—	—	—
Sales	—	—	—
Settlements	(5)	2	(3)
Transfers in (out) of Level 3	—	—	—
December 31, 2011 Balance	$1	$(7)	$(6)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	—	(1)	(1)
Purchases	8	(7)	1
Issues	—	—	—
Sales	—	—	—

Settlements	(1)	9	8
Transfers in (out) of Level 3	—	—	—
June 30, 2012 Balance	$8	$(6)	$2

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, 2012:

	Fair Value as of June 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$2	Model	RTO auction clearing prices	($3.60) to $4.90	$0.50	Dollars/MWH

OE

Recurring Fair Value Measurements	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$—	$—	$—	$—	$3	$—	$3
U.S. government debt securities	—	138	—	138	—	132	—	132
Other[(1)]	—	3	—	3	—	2	—	2
Total assets[(2)]	$—	$141	$—	$141	$—	$137	$—	$137

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

(2) Excludes $1 million as of June 30, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

JCP&L

Recurring Fair Value Measurements	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$149	$—	$149	$—	$144	$—	$144
Derivative assets - NUG contracts[(1)]	—	—	4	4	—	—	4	4
Equity securities[(2)]	30	—	—	30	30	—	—	30
U.S. government debt securities	—	—	—	—	—	2	—	2
U.S. state debt securities	—	223	—	223	—	219	—	219
Other[(3)]	—	19	—	19	—	15	—	15
Total assets	30	391	4	425	30	380	4	414
Liabilities								
Derivative liabilities - NUG contracts[(1)]	—	—	(125)	(125)	—	—	(147)	(147)
Derivative liabilities - LCAPP contracts[(1)]	—	—	(145)	(145)	—	—	—	—
Total liabilities	—	—	(270)	(270)	—	—	(147)	(147)
Net assets (liabilities)[(4)]	$30	$391	$(266)	$155	$30	$380	$(143)	$267

(1) NUG and LCAPP 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.

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

(4) Excludes $2 million as of June 30, 2012 and December 31, 2011 of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and LCAPP contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the periods ended June 30, 2012 and December 31, 2011:

	NUG Contracts(1)			LCAPP Contracts(1)		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
January 1, 2011 Balance	$6	$(233)	$(227)	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—
Unrealized gain (loss)	(2)	(11)	(13)	—	—	—
Purchases	—	—	—	—	—	—
Issuances	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	97	97	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
December 31, 2011 Balance	$4	$(147)	$(143)	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—
Unrealized gain (loss)	—	(7)	(7)	—	—	—
Purchases	—	—	—	—	(145)	(145)
Issues	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	29	29	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
June 30, 2012 Balance	$4	$(125)	$(121)	$—	$(145)	$(145)

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

Level 3 Quantitative Information

The following table provides quantitative information for NUG and LCAPP contracts held by JCP&L that are classified as Level 3 in the fair value hierarchy for the period ended June 30, 2012:

	Fair Value as of June 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
NUG Contracts	$(121)	Model	Generation Electricity regional prices	63,000 to 715,000 $49.50 to $84.90	166,000 $65.80	MWH Dollars/MWH
LCAPP Contracts	$(145)	Model	Regional capacity prices	$94.90 to $248.40	$183.90	Dollars/MW-Day

INVESTMENTS

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

FE and its subsidiaries periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold an equity investment until recovery and then consider, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FE and its subsidiaries consider their intent to hold the security, the likelihood that they will be required to sell the security before recovery of their cost basis and the likelihood of recovery of the security's entire amortized cost basis.

Unrealized gains applicable to the decommissioning trusts of FES and OE are recognized in OCI because fluctuations in fair value will eventually impact earnings while unrealized losses are recorded to earnings. The decommissioning trusts of JCP&L are subject to regulatory accounting. Net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in the trust and the decommissioning liabilities will be recovered from or refunded to customers.

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, preferred stocks, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

Available-For-Sale Securities

FES, OE and JCP&L hold debt and equity securities within their NDT, nuclear fuel disposal trusts and NUG trusts. These trust investments are considered available-for-sale securities at fair market value. FES, OE and JCP&L have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in NDT, nuclear fuel disposal trusts and NUG trusts as of June 30, 2012 and December 31, 2011:

	June 30, 2012[1]				December 31, 2011[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities								
FE Consolidated	$2,032	$52	$—	$2,084	$1,980	$25 25	$—	—$2,005
FES	1,034	29	—	1,063	1,012	13	—	1,025
OE	138	—	—	138	134	—	—	134
JCP&L	358	12	—	370	356	7	—	363
Equity securities								
FE Consolidated	$243	$36	$—	$279	$222	$36	$—	$258
FES	125	19	—	144	104	20	—	124
JCP&L	27	3	—	30	27	3	—	30

(1) Excludes short-term cash investments: FE Consolidated - $113 million; FES - $42 million; OE - $3 million; JCP&L - $23 million.

(2) Excludes short-term cash investments: FE Consolidated - $164 million; FES - $74 million; OE - $2 million; JCP&L - $19 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales and interest and dividend income for the three months and six months ended June 30, 2012 and 2011 were as follows:

Three Months Ended

June 30, 2012	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FE Consolidated	$131	$17	$(18)	$18
FES	25	13	(14)	11
OE	20	—	—	1
JCP&L	70	1	(1)	3
June 30, 2011	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FE Consolidated	$734	$22	$(16)	$28
FES	297	10	(7)	17
OE	12	—	—	1
JCP&L	159	4	(2)	4

Six Months Ended				
June 30, 2012	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FE Consolidated	$382	$37	$(35)	$33
FES	109	26	(25)	18
OE	57	—	—	1
JCP&L	165	2	(2)	7
June 30, 2011	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FE Consolidated	$1,703	$122	$(45)	$52
FES	513	22	(23)	32
OE	20	—	—	2
JCP&L	376	26	(6)	8

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains and approximate fair values of investments in held-to-maturity securities as of June 30, 2012 and December 31, 2011:

	June 30, 2012			December 31, 2011		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FE Consolidated	$326	$55	$381	$402	$50	$452
OE	148	32	180	163	21	184

Investments in emission allowances, employee benefit trusts and cost and equity method investments totaling $716 million as of June 30, 2012, and $693 million as of December 31, 2011, 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 in "Short-term borrowings" on the Consolidated Balance Sheets at cost, which approximates 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, as of June 30, 2012 and December 31, 2011:

	June 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FE Consolidated	$16,571	$18,998	$17,165	$19,320
FES	3,617	3,862	3,675	3,931
OE	1,157	1,493	1,157	1,434
JCP&L	1,762	2,076	1,777	2,080

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 listed above. 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, 2012 and December 31, 2011.

7. 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 these contractual derivative agreements through December 2018.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating interest rates and commodity prices. The effective portion of gains and losses on a derivative contract are reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains included in AOCI associated with de-designated cash flow hedges totaled $15 million and $19 million as of June 30, 2012 and December 31, 2011, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Reclassifications from AOCI into other operating expenses were $1 million and $14 million during the three months ended June 30, 2012 and 2011, respectively, and $4 million and $19 million during the six months ended June 30, 2012 and 2011, respectively. Approximately $9 million is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. As of June 30, 2012, no forward starting swap agreements accounted for as a cash flow hedge were outstanding. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $74 million as of June 30, 2012. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months. Reclassifications from AOCI into interest expense totaled $2 million and $3 million during the three months ended June 30, 2012 and 2011, respectively, and $5 million and $6 million during the six months ended June 30, 2012 and 2011, respectively.

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, 2012, 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 $91 million as of June 30, 2012. Based on current estimates, approximately $23 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $6 million during the three months ended June 30, 2012 and 2011, and $11 million during the six months ended June 30, 2012 and 2011.

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 peaking units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy's coal transportation contracts.

As of June 30, 2012, FirstEnergy's net asset position under commodity derivative contracts was $78 million, which related to FES and AE Supply positions. Under these commodity derivative contracts, FES posted $34 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $12 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, 2012, an adverse 10% change in commodity prices would decrease net income by approximately $2 million during the next twelve months.

Interest Rate Swaps

FirstEnergy uses forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives are considered economic hedges, protecting against the risk of increases in future interest payments resulting from increases in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During the three months ended June 30, 2012, FirstEnergy executed forward starting swap agreements expiring December 31, 2013, with sixteen separate counterparties for a combined notional value of $1.6 billion in order to lock in interest rates on planned debt issuances, which includes refinancings. The total portfolio of swaps carries a weighted average 10-year fixed rate of 2.315%. Changes in the fair value of the forward starting swap agreements are recorded in net income on a mark-to-market basis.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintains two LCAPP contracts, which 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. During the second quarter of 2012, JCP&L began to account for these contracts as derivatives as a result of the generators clearing the 2015/2016 PJM RPM capacity auction. JCP&L expects 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 are reflected on the Consolidated Balance Sheets as derivative liabilities (assets) with a corresponding regulatory asset (liability). Since the LCAPP contracts are subject to regulatory accounting, changes in their fair value do not impact earnings.

FTRs

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 FirstEnergy’s unregulated subsidiaries are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy’s regulated subsidiaries 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.

The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets:
Derivatives not designated as hedging instruments:

Derivative Assets	Fair Value June 30, 2012 (In millions)	December 31, 2011	Derivative Liabilities	Fair Value June 30, 2012 (In millions)	December 31, 2011
Power Contracts			Power Contracts		
Current Assets	$232	$185	Current Liabilities	$(213)	$(196)
Noncurrent Assets	106	79	Noncurrent Liabilities	(49)	(51)
FTRs			FTRs		
Current Assets	12	1	Current Liabilities	(8)	(22)
Noncurrent Assets	—	—	Noncurrent Liabilities	(1)	(1)
NUGs	9	56	NUGs	(302)	(349)
LCAPP	—	—	LCAPP	(145)	—
Interest Rate Swaps			Interest Rate Swaps		
Noncurrent Assets	3	—	Noncurrent Liabilities	(23)	—
Other			Other		
Current Assets	4	—	Current Liabilities	(1)	—
	$366	$321		$(742)	$(619)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of June 30, 2012:

	Purchases (In millions)	Sales	Net	Units
Power Contracts	29	40	(11)	MWH
FTRs	82	—	82	MWH
Interest Rate Swaps	1,600	—	1,600	notional dollars
NUGs	22	—	22	MWH
LCAPP	408	—	408	MW
Natural Gas	26	—	26	Million BTUs

The effect of derivative instruments on the Consolidated Statements of Income during the three months ended June 30, 2012 and 2011, are summarized in the following tables:

	Three Months Ended June 30				
	Power Contracts (In millions)	FTRs	Interest Rate Swaps	Other	Total
Derivatives in a Hedging Relationship					
2012					
Gain (Loss) Recognized in AOCI (Effective Portion)	$1	$—	$—	$—	$1
2011					
Gain (Loss) Recognized in AOCI (Effective Portion)	$14	$—	$—	$—	$14
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain (Loss) Recognized in:					
Other Operating Expense	$7	$12	$—	$5	$24
Interest Expense	—	—	(20)	—	(20)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(104)	$—	$—	$—	$(104)
Revenues	95	5	—	—	100
Other Operating Expense	—	(18)	—	—	(18)
Fuel Expense	—	—	—	(1)	(1)
Interest Expense	—	—	—	—	—
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$33	$—	$—	$—	$33
Revenues	(4)	—	—	—	(4)
Other Operating Expense	(34)	11	—	—	(23)
Interest Expense	—	—	—	—	—
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$1	$—	$—	$—	$1
Revenues	(39)	13	—	—	(26)
Other Operating Expense	—	(40)	—	—	(40)
Interest Expense	—	—	—	—	—

	Six Months Ended June 30				
	Power Contracts (In millions)	FTRs	Interest Rate Swaps	Other	Total
Derivatives in a Hedging Relationship					
2012					
Gain (Loss) Recognized in AOCI (Effective Portion)	$(4)	$—	$—	$—	$(4)
2011					
Gain (Loss) Recognized in AOCI (Effective Portion)	$5	$—	$—	$—	$5
Effective Gain (Loss) Reclassified to:					
Purchased Power Expense	16	—	—	—	16
Revenues	(12)	—	—	—	(12)
Fuel Expense	—	—	—	—	—
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain (Loss) Recognized in:					
Other Operating Expense	$62	$17	$—	$3	$82
Interest Expense	—	—	(20)	—	(20)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(221)	$—	$—	$—	$(221)
Revenues	206	11	—	—	217
Other Operating Expense	—	(41)	—	—	(41)
Fuel Expense	—	—	—	(1)	(1)
Interest Expense	—	—	—	—	—
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$61	$—	$—	$—	$61
Revenues	(3)	—	—	—	(3)
Other Operating Expense	(54)	12	1	—	(41)
Interest Expense	—	—	—	—	—
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(36)	$—	$—	$—	$(36)
Revenues	(29)	16	(1)	—	(14)
Other Operating Expense	—	(54)	—	—	(54)
Interest Expense	—	—	—	—	—

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during the three and six months ended June 30, 2012 and 2011, are summarized in the following tables:

	Three Months Ended June 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Gain (Loss) to Derivative Instrument	$(54)	$(145)	$—	$—	$(199)
Realized Gain (Loss) to Derivative Instrument	61	—	5	—	66
2011					
Unrealized Gain (Loss) to Derivative Instrument	$(147)	$—	$2	$—	$(145)
Realized Gain (Loss) to Derivative Instrument	62	—	—	—	62

	Six Months Ended June 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Gain (Loss) to Derivative Instrument	$(133)	$(145)	$(1)	$—	$(279)
Realized Gain (Loss) to Derivative Instrument	133	—	9	—	142
2011					
Unrealized Gain (Loss) to Derivative Instrument	$(236)	$—	$2	$—	$(234)
Realized Gain (Loss) to Derivative Instrument	134	—	(10)	—	124

The following table provides 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, 2012 and 2011:

	Three Months Ended June 30				
Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Outstanding net asset (liability) as of April 1, 2012	$(300)	$—	$(5)	$—	$(305)
Additions/Change in value of existing contracts	(54)	(145)	—	—	(199)
Settled contracts	61	—	5	—	66
Outstanding net asset (liability) as of June 30, 2012	$(293)	$(145)	$—	$—	$(438)
Outstanding net asset (liability) as of April 1, 2011	$(362)	$—	$—	$—	$(362)
Additions/Change in value of existing contracts	(147)	—	2	—	(145)
Settled contracts	62	—	—	—	62
Outstanding net asset (liability) as of June 30, 2011	$(447)	$—	$2	$—	$(445)

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Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Six Months Ended June 30 NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Outstanding net asset (liability) as of January 1, 2012	$(293)	$—	$(8)	$—	$(301)
Additions/Change in value of existing contracts	(133)	(145)	(1)	—	(279)
Settled contracts	133	—	9	—	142
Outstanding net asset (liability) as of June 30, 2012	$(293)	$(145)	$—	$—	$(438)
Outstanding net asset (liability) as of January 1, 2011	$(345)	$—	$—	$10	$(335)
Additions/Change in value of existing contracts	(236)	—	2	—	(234)
Settled contracts	134	—	—	(10)	124
Outstanding net asset (liability) as of June 30, 2011	$(447)	$—	$2	$—	$(445)

(1) Changes in the fair value of certain contracts are deferred for future recovery from (or credited to) customers.

8. 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.

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 overseen by the MDPSC and a third party monitor. The settlements with respect to residential SOS for PE customers expire on December 31, 2012, but by statute service will continue in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential service have expired but, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. In 2008, PE filed its comprehensive plans for attempting to achieve those goals, asking the MDPSC to approve programs for residential, commercial, industrial, and governmental customers, as well as a customer education program. The MDPSC ultimately approved the programs in August 2009 after certain modifications had been made as required by the MDPSC, and approved cost recovery for the programs in October 2009. Expenditures were estimated to be approximately $101 million for the PE programs for the period of 2009 to 2015 and would be recovered over that six-year period. Maryland law only allows for the utility to recover lost distribution revenue attributable to the 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. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan that includes additional and improved programs for the period 2012-2014. The plan is expected to cost approximately $66 million over the three-year period. The MDPSC held hearings on PE and the other utilities' plans in October 2011, and on December 22, 2011, issued an order approving PE's plan with various modifications and follow-up assignments.

Pursuant to a bill passed by the Maryland legislature, the MDPSC proposed rules, based on the product of a working group of utilities, regulators, and other interested stakeholders, 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 bill requires that the MDPSC consider cost-effectiveness, and provides that the MDPSC may adopt different standards for different utilities based on such factors as system design and existing infrastructure, geography, and customer density. Beginning in July 2013, the MDPSC is required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. Further comments were filed regarding the proposed rules on March 26, 2012, and at a hearing on April 17, 2012, the MDPSC approved re-publication of the rules as final.

NEW JERSEY

JCP&L currently provides BGS for retail customers that do not choose a third party electric generation supplier and for customers of third party electric generation suppliers 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. The most recent BGS auction results, for supply commencing June 1, 2012, were approved by the NJBPU on February 9, 2012.

On September 8, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, affirming the determination made at its July 18, 2012 agenda meeting, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that the Company 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 on or before November 1, 2012. JCP&L is unable to predict the outcome of this matter.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held to solicit comments regarding the state of preparedness and responsiveness of the EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 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 report of the consultant is due to be submitted to the NJBPU in August 2012. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

OHIO

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

- Generation supplied through a CBP commencing June 1, 2011;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million dependent on the outcome of certain PJM proceedings, agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their current ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012.

As approved, the ESP 3 plan will maintain the substantial benefits from the current ESP including:

- Freezing current base distribution rates through May 31, 2016;
-

- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at the levels established in the existing ESP;
- Providing Percentage of Income Payment Plan customers with a 6 percent generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan will provide additional new benefits, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in October 2012 and January 2013, to mitigate any potential price spikes for FirstEnergy Ohio utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing renewable energy credits mandated by SB 221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all FirstEnergy Ohio non-shopping utility customers by spreading out the costs over the entire ESP period.

The filing is supported by 19 parties including: Industrial Energy Users, Ohio Energy Group, PUCO Staff, the City of Akron, Ohio Manufacturers Association, Ohio Partners for Affordable Energy, and the Council of Smaller Enterprises (COSE). Seven additional parties agreed not to oppose the filing.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. Utilities were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018.

In December 2009, the Ohio Companies filed their three-year portfolio plan, as required by SB221, seeking approval for the programs they intended to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. In March 2011, the PUCO issued an Opinion and Order generally approving the Ohio Companies' 2010-2012 portfolio plan which provides for recovery of all costs associated with the programs, including lost revenues. The Ohio Companies have implemented those programs included in the plan. However, due to the timing of the approval of the plan, the Ohio Companies requested that the PUCO amend the energy efficiency and peak demand reduction benchmarks for 2010. On May 19, 2011, the PUCO granted the request to reduce the 2010 energy efficiency and peak demand reductions to the level achieved in 2010 for OE, while finding that the issue was moot for CEI and TE because they achieved their targets in that year. Failure to comply with the benchmarks or to obtain such an amendment may subject the Ohio Companies to an assessment of a penalty by the PUCO.

The Ohio Companies had filed applications for rehearing regarding portions of the PUCO's decision related to the Ohio Companies' three-year portfolio plan, which was later denied. On December 30, 2011, the Ohio Companies filed a notice of appeal with the Supreme Court of Ohio, which was dismissed on June 20, 2012. In accordance with PUCO Rules and a PUCO directive, the Ohio Companies filed their next three-year portfolio plan for the period January 1, 2013 through December 31, 2015 on July 31, 2012.

Additionally, under SB221, electric utilities and electric service companies are required to serve part of their load in 2011 from renewable energy resources equivalent to 1.00% of the average of the KWH they served in 2008-2010; in 2012 from renewable energy resources equivalent to 1.50% of the average of the KWH they served in 2009-2011; and in 2013 from renewable energy resources equivalent to 2.00% of the average of the KWH they served in 2010-2012. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RECs acquired through these two RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. The PUCO selected auditors to perform a financial and management audit, and final audit reports are currently scheduled to be filed with the PUCO on August 15, 2012. In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies have achieved their in-state solar compliance requirements for 2012.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire May 31, 2013, and provide for the competitive procurement of generation supply for customers that do not choose an alternative electric generation supplier or for customers of alternative electric generation suppliers 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 17, 2011, the Pennsylvania Companies filed a Joint Petition for Approval of their DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2013 through May 31, 2015. The ALJ issued a Recommended Decision on June 15, 2012, that supported adoption of the Pennsylvania Companies' proposed wholesale procurement plans, denial of their proposed Market Adjustment Charge, and various modifications to the proposed competitive enhancements. Exceptions to the Recommended Decision are currently pending. A final order must be entered by the PPUC by August 17, 2012.

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 began to refund those amounts to customers in January 2011, and the refunds are continuing over a 29 month period until the full amounts previously recovered for marginal transmission losses are refunded. In April 2010, ME and PN filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC's March 3, 2010 Order. On June 14, 2011, the Commonwealth Court issued an opinion and order affirming 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 and PN TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court and also a complaint seeking relief in the U.S. District Court for the Eastern District of Pennsylvania, which was subsequently amended. The PPUC filed a Motion to Dismiss ME and PN Amended Complaint on September 15, 2011 to which ME and PN responded and which remains pending. On February 28, 2012, the Supreme Court of Pennsylvania denied the Petition for Allowance of Appeal. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. The PPUC's brief in opposition is due on August 31, 2012, and the ME/PE reply is due on September 10, 2012. If the Supreme Court declines to take the case then ME and PE will pursue their claims in the proceedings that are pending in the U.S. District Court (E.D. PA).

In each of May 2008, 2009 and 2010, the PPUC approved ME's and PN's annual updates to their TSC rider for the annual periods between June 1, 2008 to December 31, 2010, including marginal transmission losses as approved by the PPUC, although the recovery of marginal transmission losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The PPUC's approval in May 2010 authorized an increase to the TSC for ME's customers to provide for full recovery by December 31, 2010. Although the ultimate outcome of this matter cannot be determined at this time, ME and PN believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million in marginal transmission losses for the period prior to January 1, 2011.

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 upon utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a final 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 has been unable to provide final results because several customers are still accumulating necessary documentation for projects that may qualify for inclusion in the final results. Preliminary numbers indicate that WP did not achieve its 2011 benchmark and it is not known at this time whether WP will be subject to a fine for failure to achieve the benchmark. WP is unable to predict the outcome of this matter or estimate any possible loss or range of loss.

On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes measures and a new program and implementation strategies consistent with the successful EE&C programs of ME, PN and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements. On January 6, 2012, a Joint Petition for Settlement of all issues was filed by the parties to the proceeding, and the ALJ's Recommended Decision was issued on April 19, 2012, recommending that the Joint Settlement be adopted as filed. The PPUC entered an order on May 10, 2012 approving the Joint Settlement.

In addition, Act 129 required utilities to file a SMIP with the PPUC. In light of the significant expenditures that would be associated with its smart meter deployment plans and related infrastructure upgrades, as well as its evaluation of recent PPUC decisions approving less-rapid deployment proposals by other utilities, WP re-evaluated its Act 129 compliance strategy, including both its plans with respect to its previously approved smart meter deployment plan and certain smart meter dependent aspects of the EE&C Plan. WP proposed to decelerate its previously contemplated smart meter deployment schedule and to target the installation of approximately 25,000 smart meters in support of its EE&C Plan, based on customer requests, by mid-2012. WP also proposed to take advantage of the 30-month grace period authorized by the PPUC to continue WP's efforts to re-evaluate full-scale smart meter deployment plans. WP would be permitted to recover certain previously incurred and anticipated smart-meter related expenditures through a levelized customer surcharge, with certain expenditures amortized over a ten-year period. A joint settlement with all parties based on these terms, with one party retaining the ability to challenge the recovery of amounts spent on WP's original smart meter implementation plan, was approved by the PPUC on June 30, 2011. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file by the end of 2012, or in a future base distribution rate case. The deadline for the Pennsylvania Companies to file their smart meter deployment plan is December 31, 2012.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market will 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. Following the issuance of a Tentative Order and comments filed by numerous parties, the PPUC entered a final order on December 16, 2011, providing recommendations for components to be included in upcoming DSPs, including: the duration of the programs and the length of associated energy contracts; a customer referral program; a retail opt-in auction; time-of-use rate options provided through contracts with electric generation suppliers; and periodic rate adjustments. Following the issuance of a Tentative Order and comments filed by various parties, the PPUC entered a final order on March 2, 2012 outlining an intermediate work plan. Several suggested models for long-range default service have been presented and were the topic of a March 2012 en banc hearing. It is expected that a tentative order will be issued for comment with a final long-range proposal.

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

WEST VIRGINIA

In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in a proceeding for an annual increase in retail rates 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 approved the Joint Petition and Agreement of Settlement in June 2010.

In January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities for purposes of compliance with their approved plan pursuant to AREPA. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the AREPA. Further, in February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP is entitled to all alternative and renewable energy resource credits associated with the electric energy, or energy and capacity, that MP is required to purchase pursuant to electric energy purchase agreements between MP and three NUG facilities in West Virginia. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, have participated in the case in opposition to the petition. The WVPSC issued an order granting ownership of all RECs produced by the facilities to MP. The West Virginia Supreme Court issued an Order on June 11, 2012, upholding the WVPSC's decision.

The City of New Martinsville and Morgantown Energy Associates have also filed complaints at FERC alleging the WVPSC order violated PURPA and requested FERC initiate an enforcement action. On April 24, 2012, the FERC ruled that the FERC-jurisdictional contracts are intended to pay only for electric energy and capacity (and not for RECs), and that state law controlled on the issues of determining which entity owns RECs and how they are transferred between entities. The FERC declined to act on the complaints and instead noted that the City of New Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. FERC also noted there may be language in the WVPSC decision that is inconsistent with PURPA. MP filed for rehearing of the FERC's order taking the position that the WVPSC order is consistent with PURPA. New Martinsville filed a complaint in the U.S. District Court on June 4, 2012, alleging that the WVPSC order violates PURPA.

On March 9, 2012, to assist the WVPSC with inquiries from public officials and the public, MP provided information to the WVPSC in the form of a closed entry filing in the ENEC case related to the plant deactivations. On April 2, 2012, the WVPSC issued an order requesting additional information from MP related to the Albright, Rivesville and Willow Island plant deactivation announcements. On April 30, 2012, MP provided the WVPSC with additional information regarding the plant deactivations. The WVPSC issued an order on July 13, 2012 finding the information provided to be sufficient and FirstEnergy's decision to deactivate the three plants reasonable. The WVPSC concluded FirstEnergy may proceed with its plan to deactivate the plants. MP anticipates deactivating these units by September 1, 2012.

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, FGCO, FENOC, ATSI and TrAIL. The 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. The financial impact of complying with future new or amended standards cannot be determined at this time; however, 2005 amendments to the FPA provide that all prudent costs incurred to comply with the future reliability standards be recovered in rates. Any future 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.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. On March 22, 2012, NERC concluded the investigation of the matter and forwarded it to NCEA for further review. NCEA is currently evaluating the findings of the investigation. JCP&L expects the matter to be resolved for an immaterial amount.

In 2011, RFC performed routine compliance audits of parts of FirstEnergy's bulk-power system and generally found the audited systems and processes to be in full compliance with all audited reliability standards. RFC will perform additional audits in 2012.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. The matter is contentious because costs for facilities built in one transmission zone often are allocated to customers in other transmission zones. During recent years, the debate has focused on the question of the methodology for determining the transmission zones and customers who benefit from a given facility and, if so, whether the methodology can determine the pro rata share of each zone's benefit. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" 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. This debate is framed by regulatory and court decisions. In 2007, 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 load serving entities in PJM bearing the majority of the costs. Subsequently, numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. 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 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.

Order No. 1000 issued by FERC on July 21, 2011, requires the submission of a compliance filing in October 2012 by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfies the principles set forth in the order. The PJM transmission owners have announced their intention to submit a compliance filing based on a hybrid methodology of 50% beneficiary pays and 50% postage stamp (or socialization) to be effective for projects approved by the PJM Board on and after the effective date of the compliance filing. FirstEnergy is working with other PJM transmission owners to develop the required filing based on this proposed methodology.

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 most of the matters involved with the move have been resolved, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed; the details of which dispute are discussed below in the "MISO Multi-Value Project Rule Proposal." In addition, FERC denied certain exit fees of ATSI's transmission rate until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. ATSI has asked for rehearing of FERC's orders that address the Michigan Thumb transmission project, and the exit fee issue.

ATSI's filings and requests for rehearing on these matters, as well as the pleadings submitted by parties that oppose ATSI's position are currently pending before FERC. Finally, a negotiated agreement that requires ATSI to pay a one-time charge of $1.8 million for long term firm transmission rights that, according to the MISO, were payable upon ATSI's exit, is pending before FERC.

The final outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners (not including ATSI or FirstEnergy) jointly filed with FERC a proposed cost allocation methodology for certain new transmission projects. The new transmission projects - described as MVPs - are a class of transmission projects that are approved via MISO's MTEP process. Under MISO's proposal, the costs of “Michigan Thumb” MVP projects that were approved by MISO's Board prior to the June 1, 2011 effective date of FirstEnergy's integration into PJM would continue to be allocated to and charged to ATSI. MISO estimated that approximately $15 million in annual revenue requirements associated with the Michigan Thumb Project would be allocated to the ATSI zone upon completion of project construction.

FirstEnergy has filed pleadings in opposition to the MISO's efforts to “socialize” the costs of the Michigan Thumb Project onto ATSI or onto ATSI's customers that assert legal, factual and policy arguments. To date, FERC has responded in a series of orders that require ATSI to absorb the charges for the Michigan Thumb Project.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of the FERC's orders with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November 2011, the cases were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit with briefs due from the parties through 2012 and oral argument to be scheduled in 2013.

In February 2012, FERC issued its most recent order (February 2012 Order) regarding the Michigan Thumb Project, in which FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. MISO's Schedule 39 tariff is the vehicle through which the MISO plans to charge the Michigan Thumb project costs to ATSI. FERC also set for hearing the question of whether it is just and reasonable for ATSI to pay the Michigan Thumb project costs and, if so, the amount of and methodology for calculating ATSI's Michigan Thumb project cost responsibility. On March 28, 2012, FirstEnergy filed for clarification and rehearing of the February 2012 Order, and such request is pending before the FERC. On July 10, 2012, a prehearing conference was convened before a FERC ALJ who will determine the scope of the hearing and thereafter set the hearing schedule.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

PJM Underfunding FTR Complaint

On December 28, 2011, FES and AE Supply filed a complaint with FERC against PJM challenging the ongoing underfunding of FTR contracts, which exist to hedge against transmission congestion in the day-ahead markets. The underfunding is a result of PJM's practice of using the funds that are intended to pay the holders of FTR contracts to pay instead for congestion costs that occur in the real time markets. Underfunding of the FTR contracts resulted in losses of approximately $35 million ($0.5 million - FES; $34.5 million - AE Supply) in the 2010-2011 Delivery Year. Losses for the 2011-2012 Delivery Year are estimated to be approximately $11.5 million ($11.4 million - FES; $0.1 million - AE Supply).

On January 13, 2012, PJM filed comments describing changes to the PJM tariff that, if adopted, should remedy the underfunding issue. On March 2, 2012, FERC dismissed the complaint without prejudice, pending PJM's publication for stakeholder review and discussion, a report on the causes of the FTR underfunding and potential improvements, including modeling, which could be made to minimize the revenue inadequacy. On March 30, 2012, FES and AE Supply requested rehearing and reconsideration of the March 2, 2012 order. On July 19, 2012, FERC issued its Order on Rehearing and again dismissed FirstEnergy's complaint without prejudice. FERC noted PJM's ongoing stakeholder process and directed that if the issues were not addressed in that process FirstEnergy could file its complaint again.

FTR Allocation Complaint

On March 26, 2012, FES and AE Supply filed a complaint with FERC against PJM challenging PJM's FTR allocation rules. PJM allocates FTRs to load-serving entities in an annual allocation process, up to each LSE's peak load, based on the expected transmission capability for the upcoming planning year. If a transmission facility is scheduled to be out of service for a significant part of the year, it can result in LSEs' FTR allocations being reduced in the annual allocation. When these transmission facilities return to service during the year, PJM will create monthly FTRs to reflect the increased transmission capability during that month. However, instead of allocating these new monthly FTRs to the LSEs that were unable to obtain their full allocation of FTRs in the annual allocation process, PJM's rules instead require PJM to auction off these new monthly FTRs in the market. The complaint seeks a change to the PJM rules such that the new FTRs created each month by transmission lines returning to service would first be allocated to those LSEs that were denied a full allocation of their FTR entitlement in the annual allocation process before they are auctioned off in the market. On April 16, 2012, PJM filed its answer to the complaint. Exelon Corporation filed a protest, and several other parties filed comments. On July 11, 2012, FERC issued its Order Granting Complaint and Requiring a Compliance Filing. In the order, FERC agreed with FirstEnergy's description of the issues and with FirstEnergy's proposed changes to PJM's rules, and FERC directed PJM to submit a compliance filing within 60 days to implement the changes in the rules.

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 United States Court of Appeals for the Ninth Circuit in 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 has since remanded one of those proceedings to FERC, which arises out of claims previously filed with FERC by the California Attorney General on behalf of certain California parties against various sellers in the California wholesale power market, including AE Supply (the Lockyer case). In March 2010, the judge assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. On May 4, 2011, FERC affirmed the judge's ruling. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. By Order issued June 13, 2012, FERC denied the request for rehearing. On June 21, 2012, the California Parties appealed the FERC's decision to the Ninth Circuit Court of Appeals.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second complaint with FERC against various sellers, including AE Supply (the Brown case), again seeking refunds for trades in the California energy markets during 2000 and 2001. The above-noted trades with CDWR are the basis for including AE Supply in this additional complaint. AE Supply filed a motion to dismiss the Brown complaint that was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. By Order issued June 13, 2012, that request for rehearing also was denied. On June 21, 2012, the California Parties appealed the FERC's decision to the Ninth Circuit Court of Appeals. 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 is comprised of a 765 kV transmission line that was proposed to extend 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. In December 2010, PJM advised that its 2011 Load Forecast Report included load projections that are different from previous forecasts and that may have an impact on the proposed in-service date for the PATH Project. As part of its 2011 RTEP, and in response to a January 19, 2011, directive by a Virginia Hearing Examiner, PJM conducted a series of analyses using the most current economic forecasts and demand response commitments, as well as potential new generation resources. Preliminary analysis revealed the expected reliability violations that necessitated the PATH Project had moved several years into the future. Based on those results, PJM announced on February 28, 2011, that its Board of Managers had decided to hold the PATH Project in abeyance in its 2011 RTEP and directed FirstEnergy and AEP, as the sponsoring transmission owners, to suspend current development efforts on the project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the need for the project as part of its continuing RTEP process. PJM stated that its action did not constitute a directive to FirstEnergy and AEP to cancel or abandon the PATH Project. PJM further stated that it will complete a more rigorous analysis of the PATH Project and other transmission requirements and its Board will review this comprehensive analysis as part of its consideration of the 2011 RTEP. The PJM Board has directed the PJM staff to perform additional analysis using the 2012 RTEP assumptions and incorporating the results of the May 2012 RPM base residual auction. The PJM staff is expected to report its conclusions from this analysis to the Transmission Expansion Advisory Committee on August 9, 2012. All applications for authorization to construct the project filed with state commissions have been withdrawn.

Yards Creek

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC, a subsidiary of Public Service Enterprise Group, owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. FERC issued a license for authorization to operate the project. The existing license expires on February 28, 2013.

In February 2011, JCP&L and PSEG filed a joint application with FERC to renew the license for an additional forty years. The companies are pursuing relicensure through FERC's ILP. Under the ILP, FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the five-year ILP licensure process. FirstEnergy expects FERC to issue the new license before February 28, 2013. To the extent, however, that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended yearly as necessary to permit FERC to issue the new license.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FGCO. FGCO holds the current FERC license that authorizes ownership and operation of the project. The current FERC license will expire on November 30, 2015. FERC's regulations call for a five-year relicensing process. On November 24, 2010, and acting pursuant to applicable FERC regulations and rules, FGCO initiated the relicensing process by filing its notice of intent to relicense and related documents in the license docket.

On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and related documents necessary for the Seneca Nation to submit a competing application. Section 15 of the FPA contemplates that third parties may file a "competing application" to assume ownership and operation of a hydroelectric facility upon (i) relicensure and (ii) payment of net book value of the plant to the original owner/operator. Nonetheless, FGCO believes it is entitled to a statutory “incumbent preference” under Section 15.

The Seneca Nation and certain other intervenors have asked FERC to redefine the “project boundary” of the hydroelectric plant to include the dam and reservoir facilities operated by the U.S. Army Corps of Engineers. On May 16, 2011, FirstEnergy filed a Petition for Declaratory Order with FERC seeking an order to exclude the dam and reservoir facilities from the project. The Seneca Nation, the New York State Department of Environmental Conservation, and the U.S. Department of Interior each submitted responses to FirstEnergy's petition, including motions to dismiss FirstEnergy's petition. The “project boundary” issue is pending before FERC.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On October 11, 2011, FERC Staff issued a letter order that addressed the Revised Study Plans. In the order, FERC Staff approved FirstEnergy's Revised Study Plan, subject to a finding that the Project is located on “aboriginal lands” of the Seneca Nation. Based on this finding, FERC Staff directed FirstEnergy to consult with the Seneca Nation and other parties about the data set, methodology and modeling of the hydrological impacts of project operations. In March of 2012, FirstEnergy hosted a meeting as part of the consultation process. In that meeting, FirstEnergy reviewed its proposed methodology for conducting the hydrological impacts study and answered questions from third parties about the methodology. On April 11, 2012, the Seneca Nation and other parties filed comments on the proposed hydrologic impacts study. The study processes, including the discrete hydrological impacts study, will extend through approximately November 2013.

FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

MISO Capacity Portability

On June 11, 2012, the 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. FERC is responding to suggestions from MISO Stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. Comments are due on August 10, 2012, and reply comments are due on August 27, 2012. 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 the prices at which those auctions would clear. FirstEnergy anticipates submitting initial comments by August 10, 2012 and, depending on the comments submitted by other parties, submitting reply comments by August 27, 2012.

9. 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, 2012, outstanding guarantees and other assurances aggregated approximately $4.1 billion, consisting of parental guarantees ($0.9 billion), subsidiaries' guarantees ($2.4 billion) and other guarantees ($0.7 billion).

Of this amount, substantially all relates to guarantees of wholly-owned consolidated entities. FES' debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, and FES guarantees the debt obligations of each of FGCO and NGC. Accordingly, present and future holders of indebtedness of FES, FGCO, and NGC would have claims against each of FES, FGCO and NGC, regardless of whether their primary obligor is FES, FGCO or NGC.

COLLATERAL AND CONTINGENT-RELATED FEATURES

As part of the normal course of business, FirstEnergy and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuels, and emissions allowances. Certain bilateral agreements and derivative instruments contain provisions that require FirstEnergy or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FirstEnergy'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 FES' and AE Supply's power portfolio exposure as of June 30, 2012, FES has posted collateral of $36 million. The Regulated Distribution segment has posted collateral of $9 million.

These credit-risk-related contingent features stipulate that if the subsidiaries 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 and lower, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FirstEnergy or its subsidiaries. The following chart discloses the additional credit contingent contractual obligations as of June 30, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$373	$6	$40	$419
BB+/Ba1 Credit Ratings	$429	$6	$59	$494
Full impact of credit contingent contractual obligations	$658	$73	$73	$804

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of June 30, 2012 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 and AE Supply would be required to post $46 million and $13 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

Signal Peak and Global Rail are borrowers under a $350 million syndicated two-year senior secured term loan facility due in October 2012. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that originally shared ownership in the borrowers with FEV, have provided a guaranty of the borrowers' obligations under the facility. Following the sale of a portion of FEV's ownership interest in Signal Peak and Global Rail in the fourth quarter of 2011, FirstEnergy, WMB Loan Ventures, LLC and WMB Loan Ventures II, LLC, together with Global Mining Group, LLC and Global Holding, continued to guarantee the borrowers' obligations under the current facility. In addition, FEV, Global Mining Group, LLC and Global Holding, the entities that own direct and indirect equity interests in the borrowers, have pledged those interests to the lenders under the current facility as collateral. Global Holding is involved in negotiations to refinance the current facility with a bank facility under which it would be the borrower. In connection with such proposed refinancing, FirstEnergy expects to provide the new lenders with a guarantee of Global Holding's obligations, and FirstEnergy and WMB Marketing Ventures, LLC expect to pledge not less than two-thirds of the equity interests in Global Holding and its subsidiaries.

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, 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 FGCO 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. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

In December 2007, the states of New Jersey and Connecticut filed CAA citizen suits in the U.S. District Court for the Eastern District of Pennsylvania alleging NSR violations at the coal-fired Portland Generation Station against GenOn Energy, Inc. (formerly RRI Energy, Inc. and the current owner and operator), Sithe Energy (the purchaser of the Portland Station from ME in 1999) and ME. Specifically, these suits allege that “modifications” at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR permitting in violation of the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. The Court dismissed New Jersey's and Connecticut's claims for injunctive relief against ME, but denied ME's motion to dismiss the claims for civil penalties. The parties dispute the scope of ME's indemnity obligation to and from Sithe Energy. In February 2012, GenOn announced its plans to retire the Portland Station in January 2015 citing EPA emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. On July 27, 2012, FirstEnergy filed a motion for summary judgment arguing the Plaintiff's remaining claims for civil penalties are barred by the statute of limitations. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on “modifications” dating back to 1984. ME, JCP&L and PN, as former owners of the facilities, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant between 1991 to 1994 without preconstruction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and have filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals. PN believes the claims are without merit and intends to 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 loss or possible range of loss. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International.

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. FGCO 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 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 a 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, EPA issued another CAA section 114 request 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 vigorously defend against these CAA matters, but cannot predict their outcomes 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 Allegheny performed major modifications in violation of the PSD 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. The parties are awaiting a decision from the District Court, but there is no deadline for that decision. FirstEnergy is unable to predict the outcome or estimate the possible loss or range of loss.

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 District of Columbia 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 June 12, 2012, the EPA revised certain CSAPR state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas), certain generating unit allocations (for some units in Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and delayed from 2012 to 2014 certain allowance penalties that could apply with respect to interstate trading of NOx and SO_2 emission allowances. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit pending a decision on legal challenges argued before the Court on April 13, 2012. The Court ordered EPA to continue administration of CAIR until the Court resolves the CSAPR appeals. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's 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. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On January 26, 2012 and February 8, 2012, FGCO, MP and AE Supply announced the deactivation by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lake Shore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW (generating, on average, approximately ten percent of the electricity produced by the companies over the past three years) due to MATS and other environmental regulations. MATS has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. FirstEnergy and other entities have also petitioned EPA to reconsider and revise various regulatory requirements under MATS. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS is estimated to be $975 million and other changes to FirstEnergy's operations may result.

On March 8, 2012, FGCO filed an application for a feasibility study with PJM to install and interconnect to the transmission system 832 megawatts of new combustion turbine peaking generation at its existing Eastlake Plant in Eastlake, Ohio, to help ensure reliable electric service in the region. However, when these units did not clear the May PJM capacity auction, the decision was made to not proceed with the project at this time. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from our previously announced plant deactivations and requested RMR arrangements for Eastlake 1-3, Ashtabula 5 and Lake Shore 18. On July 10, 2012, FirstEnergy filed with FERC, for informational purposes, the compensation arrangements for these units which will remain in effect for as long as these generating units continue to operate. On July 16, 2012, FGCO and ATSI filed an application with FERC for authorization to transfer from FGCO to ATSI certain assets associated with Eastlake Units 1-5 and Lakeshore Unit 18 for conversion to synchronous condensers by ATSI for transmission reliability purposes as directed by PJM. Upon FERC approval, it is expected that the assets will be transferred in staggered closings when the units are no longer needed for RMR purposes. During the three months and six months ended June 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $10 million ($6 million by FES) and $17 million ($10 million by FES), respectively, as a result of the deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

On March 9, 2012, to assist the WVPSC with inquiries from public officials and the public, MP provided information to the WVPSC in the form of a closed entry filing in the ENEC case related to the plant deactivations. On April 2, 2012, the WVPSC issued an order requesting additional information from MP related to the Albright, Rivesville and Willow Island plant deactivation announcements. On April 30, 2012, MP provided the WVPSC with additional information regarding the plant deactivations. The WVPSC issued an order on July 13, 2012 finding the information provided to be sufficient and FirstEnergy's decision to deactivate the three plants reasonable. The WVPSC concluded FirstEnergy may proceed with its plan to deactivate the plants. MP anticipates deactivating these units by September 1, 2012.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, in June 2009. Certain states, primarily the northeastern states participating in the RGGI and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required FirstEnergy to measure and report 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 preconstruction 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.

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. 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 from 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. A December 2011 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.

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. In July 2012, the period for finalizing the Section 316(b) regulation was extended to July 27, 2013. 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 water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking 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.

In April 2011, the U.S. Attorney's Office in Cleveland, Ohio advised FGCO that it is no longer considering prosecution under the CWA and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. On June 5, 2012, FirstEnergy executed a tolling agreement with the EPA extending the statute of limitations for civil liability claims for those petroleum spills to January 31, 2013. FGCO does not anticipate any losses resulting from this matter to be material.

In late 2008, the PA DEP imposed water quality criteria for certain effluents, including TDS and sulfate concentrations in the Monongahela River, on new and modified sources, including the scrubber project at the coal-fired Hatfield's Ferry Plant. These criteria are reflected in the NPDES water discharge permit issued by PA DEP for that project. In January 2009, AE Supply appealed the PA DEP's permitting decision to the EHB, due to estimated costs in excess of $150 million in order to install technology to meet TDS and sulfate limits in the NPDES permit. Environmental Integrity Project and Citizens Coal Council also appealed the NPDES permit seeking to impose more stringent technology-based effluent limitations. In April 2012, a joint motion was filed by the parties informing the EHB of a proposed settlement and seeking the lifting of a portion of the EHB's stay of certain terms of the Hatfield's Ferry Plant's NPDES permit. The joint motion was granted by the EHB on April 27, 2012. The proposed settlement, in the form of a Consent Decree, was lodged with the Commonwealth Court of Pennsylvania and published in the June 23, 2012, Pennsylvania Bulletin for a 30-day public comment period. The Consent Decree, if entered by the Commonwealth Court of Pennsylvania, will resolve the disputes concerning the Hatfield's Ferry Plant NPDES permit, including TDS and sulphate limits.

The PA DEP recommended, and in August 2010, the Pennsylvania Environmental Quality Board issued, a final rule imposing end-of-pipe TDS effluent limitations. FirstEnergy could incur significant costs for additional control equipment to meet the requirements of this rule, although its provisions do not apply to electric generating units until the end of 2018, and then would apply only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

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. PA DEP's goal is to submit a final water quality standards regulation, incorporating the sulfate impairment designation for EPA approval by May 2013. PA DEP will then need to develop a TMDL limit for the river, a process that will take approximately five years. Based on the stringency of the TMDL, FirstEnergy may incur significant costs to reduce sulfate discharges into the Monongahela River from the coal-fired Hatfield's Ferry and Mitchell Plants in Pennsylvania and the coal-fired Fort Martin Plant in West Virginia.

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 has 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 in excess of the capital investment that may be needed at Hatfield's Ferry 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 May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit in the U.S. District Court for the Northern District of West Virginia alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash impoundments at the Albright Station seeking unspecified civil penalties and injunctive relief. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served a 60-day Notice of Intent required prior to filing a citizen suit under the CWA for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Plant. MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. On January 3, 2012, the Court denied MP's motion to dismiss or stay the CWA citizen suit but without prejudice to re-filing in the future. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. If approved by the Court, a Consent Decree will be entered by the Court to resolve these claims. MP is currently seeking relief from the arsenic limits through WVDEP agency review.

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 Resource Conservation and Recovery Act 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 coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, 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 coal combustion residuals. On July 27, 2012, the PA DEP filed a complaint against FGCO in the U.S. District Court for the Western District of Pennsylvania with claims under the Resource Conservation and Recovery Act and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FGCO to resolve those claims. The Consent Decree will be published to allow for a 30-day public comment period and requires FGCO 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 Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. BMP is pursuing several options for disposal of CCB following December 31, 2016.

FirstEnergy's future cost of compliance with any coal combustion residuals 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 our 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, 2012, 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 $122 million (including $86 million applicable to JCP&L) have been accrued through June 30, 2012. Included in the total are accrued liabilities of approximately $79 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, 2012, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. 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. FirstEnergy Corp. currently maintains a $95 million parental guaranty in support of the decommissioning of nuclear facilities.

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. By an order dated April 26, 2011, a NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. The NRC subsequently narrowed the scope of admitted contentions in this proceeding to a challenge to the computer code used to model source terms in FENOC's Severe Accident Mitigation Alternatives analysis. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the cracking of the Davis-Besse shield building discussed below. The intervenors supplemented their petition for a contention on the shield building on multiple occasions. On July 9, 2012, the intervenors petitioned the ASLB for a new contention on the environmental impacts of temporary spent fuel storage at Davis-Besse due to the lack of a repository and the disposal of these wastes. The ASLB has yet to rule on the admission of these latest requests for new contentions.

Similarly, on June 18 and 19, 2012, the intervenors in the Davis-Besse license renewal proceeding and other petitioners requested that the NRC suspends the issuance of final decisions in all pending reactor licensing proceedings as a result of the decision in the case of State of New York v. NRC, No. 11-1045. (D.C. Cir. June 8, 2012). In this case, the D.C. Circuit vacated the NRC's updated Waste Confidence Decision and its Temporary Storage Rule and remanded those rulemakings to the NRC for further consideration. FENOC and other Licensees opposed the suspension request. By order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the D.C. Circuit decision and all pending contentions on this topic should be held in abeyance until further order. The NRC also directed that all licensing reviews and proceedings should continue to move forward.

On October 1, 2011, Davis-Besse was safely shut down for a scheduled outage to install a new reactor vessel head and complete other maintenance activities. The new reactor head, which replaced a head installed in 2002, enhances safety and reliability, and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, following opening of the building for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above elevation 780') and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers has determined these conditions do not affect the facility's structural integrity or safety.

On December 2, 2011, the NRC issued a CAL which concluded that FENOC provided "reasonable assurance that the shield building remains capable of performing its safety functions." The CAL imposed a number of commitments from FENOC, including, submitting a root cause evaluation and corrective actions to the NRC by February 28, 2012, and further evaluations of the shield building. On February 27, 2012, FENOC sent the root cause evaluation to the NRC. Finally, the CAL also stated that the NRC was still evaluating whether the current condition of the shield building conforms to the plant's licensing basis. On December 6, 2011, the Davis-Besse plant returned to service. On June 21, 2012, the NRC issued an Inspection Report that concluded that FENOC established a sufficient basis for the causes of the shield building laminar cracking.

By letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff will conduct several supplemental inspections, culminating in an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues are understood, the extent of condition has been identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. Additional adverse findings by the NRC could result in further inspection activities.

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.

On February 16, 2012, the NRC issued a request for information to the licensed operators of 11 nuclear power plants, including Beaver Valley Power Station Units 1 and 2, with respect to the modeling of fuel performance as it relates to "thermal conductivity degradation," which is the potential in higher burn up fuel for reduced capacity to transfer heat that could potentially change its performance during various accident scenarios, including loss of coolant accidents. The request for information indicated that this phenomenon has not been accounted for adequately in performance models for the fuel developed by the fuel manufacturer and that the NRC might consider imposing restrictions on reactor operating limits. On March 16, 2012, FENOC submitted its response to the NRC demonstrating that the NRC requirements are being met. FENOC also agreed to submit to the NRC revised large break loss of coolant accident analyses by December 15, 2016, that further consider the effects of fuel pellet thermal conductivity degradation.

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 Coal Sales Agreement 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, which issue can be the subject of a future appeal. 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 have 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 claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to 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 replacement coal / 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, ICG posted bond and filed a Notice of Appeal. Briefing on the Appeal has concluded and an oral argument was held on May 16, 2012. A decision from the Appellate court is expected in the fourth quarter of 2012. AE Supply and MP intend to vigorously pursue this matter through appeal.

Other Legal Matters

In February 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount had been approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction. The court granted the motion to dismiss and the plaintiffs appealed the decision to the Court of Appeals of Ohio. The Court of Appeals affirmed the dismissal of the Complaint by the Court of Common Pleas on all counts except for one relating to an allegation of fraud which it remanded to the trial court. The Companies timely filed a notice of appeal with the Supreme Court of Ohio on December 5, 2011, challenging this one aspect of the Court of Appeals opinion. The Supreme Court of Ohio agreed to hear the appeal.

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 other potentially material items not otherwise discussed above are described under Note 8, Regulatory Matters to the Combined Notes to the 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 and 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.

10. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FGCO completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully, unconditionally and irrevocably guaranteed all of FGCO’s obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, 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 under GAAP for FES and FirstEnergy and as a financing for FGCO.

The Condensed Consolidating Statements of Income and Comprehensive Income for the three months and six months ended June 30, 2012 and 2011, Consolidating Balance Sheets as of June 30, 2012 and December 31, 2011, and Consolidating Statements of Cash Flows for the six months ended June 30, 2012 and 2011, for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC 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 AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended June 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,430	$636	$473	$(1,083)	$1,456
OPERATING EXPENSES:					
Fuel	—	336	44	—	380
Purchased power from affiliates	1,156	—	60	(1,083)	133
Purchased power from non-affiliates	434	—	—	—	434
Other operating expenses	107	100	172	14	393
Provision for depreciation	1	30	39	(1)	69
General taxes	20	8	4	—	32
Total operating expenses	1,718	474	319	(1,070)	1,441
OPERATING INCOME (LOSS)	(288)	162	154	(13)	15
OTHER INCOME (EXPENSE):					
Investment income	—	5	7	(6)	6
Miscellaneous income, including net income from equity investees	279	19	—	(278)	20
Interest expense — affiliates	(5)	(2)	(1)	6	(2)
Interest expense — other	(24)	(26)	(14)	16	(48)
Capitalized interest	—	1	8	—	9
Total other income (expense)	250	(3)	—	(262)	(15)
INCOME (LOSS) BEFORE INCOME TAXES	(38)	159	154	(275)	—
INCOME TAXES (BENEFITS)	(37)	(7)	42	3	1
NET INCOME (LOSS)	$(1)	$166	$112	$(278)	$(1)
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME (LOSS)	$(1)	$166	$112	$(278)	$(1)
OTHER COMPREHENSIVE INCOME:					
Pensions and OPEB prior service costs	8	7	—	(7)	8
Amortized gain on derivative hedges	1	—	—	—	1
Change in unrealized gain on available for sale securities	3	—	3	(3)	3
Other comprehensive income	12	7	3	(10)	12
Income taxes on other comprehensive income	2	3	1	(4)	2
Other comprehensive income, net of tax	10	4	2	(6)	10

COMPREHENSIVE INCOME	$9	$170	$114	$(284)	$9

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

For the Six Months Ended June 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$2,920	$1,178	$867	$(1,993)	$2,972
OPERATING EXPENSES:					
Fuel	—	576	99	—	675
Purchased power from affiliates	2,121	—	122	(1,993)	250
Purchased power from non-affiliates	921	—	—	—	921
Other operating expenses	183	192	288	25	688
Provision for depreciation	2	60	73	(3)	132
General taxes	40	18	11	—	69
Total operating expenses	3,267	846	593	(1,971)	2,735
OPERATING INCOME (LOSS)	(347)	332	274	(22)	237
OTHER INCOME (EXPENSE):					
Investment income	1	9	12	(10)	12
Miscellaneous income, including net income from equity investees	537	19	—	(532)	24
Interest expense — affiliates	(9)	(3)	(2)	10	(4)
Interest expense — other	(47)	(52)	(21)	31	(89)
Capitalized interest	—	2	16	—	18
Total other income (expense)	482	(25)	5	(501)	(39)
INCOME BEFORE INCOME TAXES	135	307	279	(523)	198
INCOME TAXES (BENEFITS)	14	(8)	65	6	77
NET INCOME	$121	$315	$214	$(529)	$121
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$121	$315	$214	$(529)	$121
OTHER COMPREHENSIVE INCOME					
Pensions and OPEB prior service costs	3	3	—	(3)	3
Amortized loss on derivative hedges	(4)	—	—	—	(4)
Change in unrealized gain on available for sale securities	13	—	13	(13)	13
Other comprehensive income	12	3	13	(16)	12
Income taxes on other comprehensive income	4	1	5	(6)	4
Other comprehensive income, net of tax	8	2	8	(10)	8
	$129	$317	$222	$(539)	$129

COMPREHENSIVE INCOME

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

For the Three Months Ended June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,275	$535	$393	$(911)	$1,292
OPERATING EXPENSES:					
Fuel	6	266	44	—	316
Purchased power from affiliates	902	9	65	(911)	65
Purchased power from non-affiliates	332	(3)	—	—	329
Other operating expenses	159	108	134	12	413
Provision for depreciation	1	32	37	(1)	69
General taxes	16	8	6	—	30
Impairment of long-lived assets	—	7	—	—	7
Total operating expenses	1,416	427	286	(900)	1,229
OPERATING INCOME (LOSS)	(141)	108	107	(11)	63
OTHER INCOME (EXPENSE):					
Investment income	—	1	15	—	16
Miscellaneous income, including net income from equity investees	132	1	—	(129)	4
Interest expense — affiliates	—	(1)	(1)	—	(2)
Interest expense — other	(24)	(28)	(16)	16	(52)
Capitalized interest	—	5	5	—	10
Total other income (expense)	108	(22)	3	(113)	(24)
INCOME (LOSS) BEFORE INCOME TAXES	(33)	86	110	(124)	39
INCOME TAXES (BENEFITS)	(62)	28	41	3	10
NET INCOME	$29	$58	$69	$(127)	$29
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$29	$58	$69	$(127)	$29
OTHER COMPREHENSIVE INCOME (LOSS)					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized gain on derivative hedges	14	—	—	—	14
Change in unrealized gain on available for sale securities	8	—	8	(8)	8
Other comprehensive income (loss)	17	(4)	8	(4)	17

Income taxes (benefits) on other comprehensive income (loss)	8	(2)	3	(1)	8
Other comprehensive income (loss), net of tax	9	(2)	5	(3)	9
COMPREHENSIVE INCOME	$38	$56	$74	$(130)	$38

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

For the Six Months Ended June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$2,642	$1,278	$862	$(2,098)	$2,684
OPERATING EXPENSES:					
Fuel	7	560	92	—	659
Purchased power from affiliates	2,087	11	134	(2,098)	134
Purchased power from non-affiliates	629	(3)	—	—	626
Other operating expenses	321	219	313	25	878
Provision for depreciation	2	63	76	(3)	138
General taxes	27	19	14	—	60
Impairment of long-lived assets	—	20	—	—	20
Total operating expenses	3,073	889	629	(2,076)	2,515
OPERATING INCOME (LOSS)	(431)	389	233	(22)	169
OTHER INCOME (EXPENSE):					
Investment income	1	1	20	—	22
Miscellaneous income, including net income from equity investees	374	2	—	(368)	8
Interest expense — affiliates	(1)	(1)	(1)	—	(3)
Interest expense — other	(48)	(56)	(33)	32	(105)
Capitalized interest	—	10	10	—	20
Total other income (expense)	326	(44)	(4)	(336)	(58)
INCOME (LOSS) BEFORE INCOME TAXES	(105)	345	229	(358)	111
INCOME TAXES (BENEFITS)	(179)	125	86	5	37
NET INCOME	$74	$220	$143	$(363)	$74
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$74	$220	$143	$(363)	$74
OTHER COMPREHENSIVE INCOME (LOSS)					
Pensions and OPEB prior service costs	(9)	(8)	—	8	(9)
Amortized gain on derivative hedges	5	—	—	—	5
Change in unrealized gain on available for sale securities	15	—	15	(15)	15
Other comprehensive income (loss)	11	(8)	15	(7)	11

Income taxes (benefits) on other comprehensive income (loss)	4	(4)	6	(2)	4
Other comprehensive income (loss), net of tax	7	(4)	9	(5)	7
COMPREHENSIVE INCOME	$81	$216	$152	$(368)	$81

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of June 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$7	$—	$—	$7
Receivables-					
Customers	457	—	—	—	457
Affiliated companies	464	482	297	(706)	537
Other	67	25	4	—	96
Notes receivable from affiliated companies	155	1,653	152	(1,732)	228
Materials and supplies, at average cost	68	272	208	—	548
Derivatives	265	—	—	—	265
Prepayments and other	3	15	1	—	19
	1,479	2,454	662	(2,438)	2,157
PROPERTY, PLANT AND EQUIPMENT:					
In service	89	5,620	6,051	(385)	11,375
Less — Accumulated provision for depreciation	30	1,872	2,594	(182)	4,314
	59	3,748	3,457	(203)	7,061
Construction work in progress	28	187	704	—	919
	87	3,935	4,161	(203)	7,980
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,250	—	1,250
Investment in affiliated companies	6,241	—	—	(6,241)	—
Other	—	7	—	—	7
	6,241	7	1,250	(6,241)	1,257
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	261	—	(261)	—
Customer intangibles	118		—	—	118
Goodwill	24		—	—	24
Property taxes	—	20	23	—	43
Unamortized sale and leaseback costs	—	4	—	114	118
Derivatives	110		—	—	110
Other	86	160	1	(110)	137
	338	445	24	(257)	550
	$8,145	$6,841	$6,097	$(9,139)	$11,944
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$646	$518	$(21)	$1,144
Short-term borrowings-					
Affiliated companies	1,597	135	—	(1,732)	—
Accounts payable-					
Affiliated companies	739	279	305	(715)	608
Other	173	133	—	—	306
Accrued taxes	23	20	27	(8)	62

Derivatives	219	—	—	—	219
Other	68	124	13	37	242
	2,820	1,337	863	(2,439)	2,581
CAPITALIZATION:					
Total equity	3,704	3,413	2,810	(6,223)	3,704
Long-term debt and other long-term obligations	1,482	1,657	580	(1,219)	2,500
	5,186	5,070	3,390	(7,442)	6,204
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	909	909
Accumulated deferred income taxes	28	—	572	(164)	436
Asset retirement obligations	—	29	905	—	934
Retirement benefits	34	145	—	—	179
Lease market valuation liability	—	148	—	—	148
Other	77	112	367	(3)	553
	139	434	1,844	742	3,159
	$8,145	$6,841	$6,097	$(9,139)	$11,944

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$7	$—	$—	$7
Receivables-					
Customers	424	—	—	—	424
Affiliated companies	476	643	262	(781)	600
Other	28	20	13	—	61
Notes receivable from affiliated companies	155	1,346	69	(1,187)	383
Materials and supplies, at average cost	60	232	200	—	492
Derivatives	219	—	—	—	219
Prepayments and other	11	26	1	—	38
	1,373	2,274	545	(1,968)	2,224
PROPERTY, PLANT AND EQUIPMENT:					
In service	84	5,573	5,711	(385)	10,983
Less — Accumulated provision for depreciation	28	1,813	2,449	(180)	4,110
	56	3,760	3,262	(205)	6,873
Construction work in progress	29	195	790	—	1,014
	85	3,955	4,052	(205)	7,887
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,223	—	1,223
Investment in affiliated companies	5,700	—	—	(5,700)	—
Other	—	7	—	—	7
	5,700	7	1,223	(5,700)	1,230
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	10	307	—	(317)	—
Customer intangibles	123	—	—	—	123
Goodwill	24	—	—	—	24
Property taxes	—	20	23	—	43
Unamortized sale and leaseback costs	—	5	—	75	80
Derivatives	79	—	—	—	79
Other	89	99	3	(62)	129
	325	431	26	(304)	478
	$7,483	$6,667	$5,846	$(8,177)	$11,819
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$411	$513	$(20)	$905
Short-term borrowings-					
Affiliated companies	1,065	89	32	(1,186)	—
Accounts payable-					
Affiliated companies	777	228	211	(780)	436
Other	99	121	—	—	220
Accrued taxes	84	42	110	(9)	227

Derivatives	189	—	—	—	189
Other	62	141	16	42	261
	2,277	1,032	882	(1,953)	2,238
CAPITALIZATION:					
Total equity	3,577	3,097	2,587	(5,684)	3,577
Long-term debt and other long-term obligations	1,483	1,905	641	(1,230)	2,799
	5,060	5,002	3,228	(6,914)	6,376
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	925	925
Accumulated deferred income taxes	12	—	510	(236)	286
Asset retirement obligations	—	28	876	—	904
Retirement benefits	56	300	—	—	356
Lease market valuation liability	—	171	—	—	171
Other	78	134	350	1	563
	146	633	1,736	690	3,205
	$7,483	$6,667	$5,846	$(8,177)	$11,819

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

For the Six Months Ended June 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(525)	$308	$446	$(10)	$219
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	52	30	—	82
Short-term borrowings, net	532	46	—	(578)	—
Redemptions and Repayments-					
Long-term debt	—	(63)	(87)	10	(140)
Short-term borrowings, net	—	—	(32)	32	—
Other	(1)	(4)	(1)	—	(6)
Net cash provided from (used for) financing activities	531	31	(90)	(536)	(64)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(44)	(254)	—	(303)
Proceeds from assets sale	—	17	—	—	17
Sales of investment securities held in trusts	—	—	109	—	109
Purchases of investment securities held in trusts	—	—	(127)	—	(127)
Loans to affiliated companies, net	1	(308)	(84)	546	155
Other	(2)	(4)	—	—	(6)
Net cash provided from (used for) investing activities	(6)	(339)	(356)	546	(155)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	7	—	—	7
Cash and cash equivalents at end of period	$—	$7	$—	$—	$7

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

For the Six Months Ended June 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(329)	$321	$200	$(10)	$182
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	140	107	—	247
Short-term borrowings, net	453	77	—	—	530
Redemptions and Repayments-					
Long-term debt	(135)	(192)	(155)	10	(472)
Other	(9)	(1)	(1)	—	(11)
Net cash used for financing activities	309	24	(49)	10	294
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(6)	(109)	(219)	—	(334)
Sales of investment securities held in trusts	—	—	513	—	513
Purchases of investment securities held in trusts	—	—	(545)	—	(545)
Loans to affiliated companies, net	28	(221)	100	—	(93)
Other	(2)	(18)	—	—	(20)
Net cash provided from (used for) investing activities	20	(348)	(151)	—	(479)
Net change in cash and cash equivalents	—	(3)	—	—	(3)
Cash and cash equivalents at beginning of period	—	9	—	—	9
Cash and cash equivalents at end of period	$—	$6	$—	$—	$6

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11. SEGMENT INFORMATION

During the second quarter of 2012, FirstEnergy successfully completed the integration of AE into its IT business networks and financial systems. An important element of this system integration was the capability to modify the segment reporting to reflect how management now views and makes investment decisions regarding the distribution and transmission operations of FirstEnergy. The external segment reporting is now consistent with the internal financial reports used by FirstEnergy's chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. Disclosures for FirstEnergy's operating segments for 2011 have been reclassified to conform to the current presentation.

The key changes in FirstEnergy's reportable segments during the second quarter of 2012 consisted principally of including the federally-regulated transmission assets and operations of JCP&L, ME, PN, MP, PE and WP, that were previously reported within the Regulated Distribution segment, with the renamed Regulated Transmission Segment. There were no changes to the Competitive Energy Services or Other / Corporate Segments. FirstEnergy continues to have three reportable operating segments — Regulated Distribution, Regulated Transmission and Competitive Energy Services.

Financial information for each of FirstEnergy’s reportable segments is presented in the tables below, which includes financial results for the Allegheny subsidiaries beginning February 25, 2011. FES, OE and JCP&L do 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 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.

The Regulated Transmission segment, previously known in part as the Regulated Independent Transmission Segment, transmits electricity through transmission lines owned and operated by certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and independent transmission companies (ATSI, TrAIL and PATH). Its revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Revenues are also derived from providing transmission services to electric energy providers, power marketers and revenue from operating the FirstEnergy transmission system. Its results reflect the net transmission expenses related to the delivery of the respective generation loads.

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 controls approximately 17,000 MWs of capacity, excluding approximately 2,700 MWs from unregulated plants expected to be deactivated, (see Note 8, Regulatory Matters, of the Combined Notes to Consolidated Financial Statements) and 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 purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO (prior to June 1, 2011) to deliver energy to the segment’s customers.

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, 2012						
External revenues	$2,095	$ 184	$1,616	$ (24)	$(2)	$3,869
Internal revenues	—	—	209	—	(209)	—
Total revenues	2,095	184	1,825	(24)	(211)	3,869
Depreciation and amortization	215	29	103	8	(1)	354
Investment income	19	—	6	1	(13)	13
Net interest charges	132	22	59	42	—	255
Income taxes	94	31	14	(25)	13	127
Net income	161	52	25	(42)	(8)	188
Total assets	25,787	4,473	17,216	572	—	48,048
Total goodwill	5,025	526	893	—	—	6,444
Property additions	177	59	150	26	—	412
June 30, 2011						
External revenues	$2,409	$ 182	$1,495	$ (30)	$(8)	$4,048
Internal revenues	—	—	318	—	(306)	12
Total revenues	2,409	182	1,813	(30)	(314)	4,060
Depreciation and amortization	232	28	109	8	—	377
Investment income	25	—	16	—	(10)	31
Net interest charges	134	24	69	19	(1)	245
Income taxes	100	33	12	(30)	(1)	114
Net income	171	57	21	(51)	(5)	193
Total assets	25,069	4,202	17,146	1,179	—	47,596
Total goodwill	5,025	526	885	—	—	6,436
Property additions	266	81	197	25	—	569
Six Months Ended						
June 30, 2012						
External revenues	$4,420	$ 370	$3,222	$ (47)	$(20)	$7,945
Internal revenues	—	—	477	—	(475)	2
Total revenues	4,420	370	3,699	(47)	(495)	7,947
Depreciation and amortization	435	61	203	16	(1)	714
Investment income	42	1	12	1	(32)	24
Net interest charges	264	45	113	63	(1)	484
Income taxes	187	66	97	(41)	40	349
Net income	318	112	166	(69)	(33)	494
Total assets	25,787	4,473	17,216	572	—	48,048
Total goodwill	5,025	526	893	—	—	6,444
Property additions	443	122	393	43	—	1,001
June 30, 2011						
External revenues	$4,632	$ 295	$2,736	$ (53)	$(18)	$7,592
Internal revenues	—	—	661	—	(617)	44
Total revenues	4,632	295	3,397	(53)	(635)	7,636

Depreciation and amortization	473	50	197	14	—	734
Investment income	48	—	21	1	(18)	52
Net interest charges	256	41	122	39	—	458
Income taxes	158	47	21	(30)	29	225
Net income	267	80	36	(105)	(38)	240
Total assets	25,069	4,202	17,146	1,179	—	47,596
Total goodwill	5,025	526	885	—	—	6,436
Property additions	381	170	411	56	—	1,018

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

Earnings available to FirstEnergy Corp. in the second quarter of 2012 were $187 million, or basic and diluted earnings of $0.45 per share of common stock, compared with $203 million, or basic and diluted earnings of $0.48 per share of common stock in the second quarter of 2011. Earnings available to FirstEnergy Corp. in the first six months of 2012 were $493 million or basic and diluted earnings of $1.18 per share of common stock, compared with $255 million or basic and diluted earnings of $0.67 per share of common stock in the first six months of 2011. The principal reasons for the changes in basic earnings per share are summarized below.

Change In Basic Earnings Per Share From Prior Year	Three Months Ended June 30	Six Months Ended June 30
Basic Earnings Per Share - 2011	$0.48	$0.67
Segment operating results[1] -		
Regulated Distribution	(0.01)	(0.04)
Regulated Transmission	—	(0.01)
Competitive Energy Services	(0.06)	(0.04)
Regulatory charges	—	0.02
Income Tax Charge – retiree prescription drug subsidy	(0.02)	(0.04)
Merger-related costs	0.02	0.36
Impact of non-core asset sales / impairments	0.03	0.06
Mark-to-market adjustments	0.01	0.09
Merger accounting — commodity contracts	0.04	0.04
Plant closing costs	(0.07)	(0.13)
Litigation resolution	0.05	0.05
Net merger accretion[1][2]	—	0.17
Depreciation	(0.01)	—
Interest expense, net of amounts capitalized	0.01	0.02
Investment Income	(0.02)	(0.02)
Other	—	(0.02)
Basic Earnings Per Share - 2012	$0.45	$1.18

(1) Excludes amounts that are shown separately. Allegheny results for the three months ended June 30, 2012 and 2011, are included in Segment Operating Results.

(2) Includes dilutive effect of shares issued in connection with the Allegheny merger, and three months of Allegheny results in the first three months of 2012 compared to one month during the same period of 2011.

Operational Matters

Enhancing Transmission System Reliability

On May 29, 2012, FirstEnergy announced plans to construct a series of transmission projects to enhance service reliability across its service area. The projects have been approved by PJM and will include specialized voltage regulating equipment in northern Ohio. In addition to the work in Ohio, approved transmission projects will also be undertaken in Pennsylvania, West Virginia, New Jersey and Maryland as part of FirstEnergy's ongoing commitment to enhance its transmission system reliability. FirstEnergy estimates spending between $700 million - $900 million through 2016 on these projects.

On June 14, 2012, JCP&L announced that it plans to begin work on 17 transmission construction projects over the next six months in its northern and central New Jersey service areas. These projects are part of the multi-year, $200 million LITE program, which began in 2011, to address New Jersey's growing demand for electricity and provide key enhancements to the transmission system designed to improve service reliability for JCP&L's 1.1 million customers. All of the LITE projects are being designed and built specifically to serve only JCP&L customers.

Beaver Valley Unit 1 Returns to Service After Refueling Outage

On May 11, 2012, Beaver Valley Power Station Unit 1 returned to service following an April 9, 2012 shutdown for refueling and maintenance. During the outage, 65 of the 157 fuel assemblies were exchanged and safety inspections were successfully conducted. In addition, maintenance and improvement projects were completed to ensure continued safe and reliable operations. Prior to the outage, Beaver Valley Unit 1 operated safely and reliably for 359 consecutive days during which time it generated more than 9.3 million MWH of electricity. The plant also posted an industry top-decile forced-loss rate of 0.01 percent during the 18 months of operation prior to the outage.

Davis-Besse Returns to Service After Refueling Outage

On June 13, 2012, Davis-Besse Nuclear Power Station returned to service following a May 6, 2012, shutdown for refueling and maintenance. During the outage, 68 of Davis-Besse's 177 fuel assemblies were exchanged and safety inspections, including inspections of the station's steam generators, were successfully conducted. Preventive maintenance and improvement projects also were completed that are designed to promote continued safe and reliable operations.

Storm Costs

During the last weekend of June 2012, MP, PE, WP and OE experienced significant customer outages due to a rare “derecho” wind storm. While projections for restoration costs are not finalized, estimated costs incurred in the third quarter related to this storm are expected to exceed $130 million. Approximately 70% of these estimated expenditures are anticipated to be capital-related. Most of the remaining maintenance costs are expected to be deferred for future recovery. MP and PE do not currently have regulatory authority to defer storm costs, but expect to make a filing in the third quarter of 2012 with the WVPSC requesting deferral of those costs. MP and PE can provide no assurance that they will be successful in getting WVPSC authorization for the deferral of storm costs.

Regulatory Matters

Ohio Electric Security Plan Update

On July 18, 2012, the PUCO approved the Ohio Companies' ESP allowing the Ohio Companies to essentially extend the terms of the current ESP for two additional years and establish electricity prices for their customers through May 31, 2016.

The approved ESP 3 plan will maintain the substantial benefits from the current ESP including:

- Freezing current base distribution rates through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at the levels established in the existing ESP;
- Providing Percentage of Income Payment Plan customers with a 6 percent generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

The approved ESP 3 plan provides significant additional benefits including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in October 2012 and January 2013, to mitigate any potential price spikes for FirstEnergy Ohio utility customers who do not switch to a competitive generation supplier; and
-

Extending the recovery period for costs associated with purchasing renewable energy credits mandated by SB 221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all FirstEnergy Ohio non-shopping utility customers by spreading out the costs over the entire ESP period.

The approved plan reflects the diverse interests and concerns of 19 signatories, including parties that represent residential, low-income, commercial and industrial customers, as well as competitive retail electric suppliers, schools and hospitals.

Ohio Companies Solar Renewable Energy

On April 26, 2012, FirstEnergy announced that its Ohio Companies have met the 2012 benchmarks for in-state solar renewable energy that were established under Ohio's energy law. The benchmarks were met through a successful RFP to secure 10-year SRECs. In Ohio, FirstEnergy supports the development of solar energy resources by purchasing SRECs, which represent the environmental attributes of solar renewable electricity generation. For every MWH of solar renewable electricity generated, an equivalent amount of SRECs are produced. The RFP sought and procured the delivery of 1,000 SRECs produced by generating facilities throughout Ohio for each calendar year beginning in 2012 and continuing through 2021. There were 38 qualified bids received, offering over 15 times the required SRECs being sought under the RFP.

NJBPU Update

In its written Order issued July 31, 2012, affirming the determination made at its July 18, 2012 agenda meeting, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that the Company 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 on or before November 1, 2012. JCP&L is unable to predict the outcome of this matter.

Financial Matters

In the second quarter of 2012, FirstEnergy executed a total of $1.6 billion forward starting swap agreements expiring December 31, 2013, with sixteen separate counterparties in order to lock in interest rates on planned debt issuances, which includes refinancings. The total portfolio of swaps carries a weighted average 10-year fixed rate of 2.315%.

On May 8, 2012, FET entered into a new $1 billion revolving credit facility. In conjunction with this action, an existing $450 million TrAIL revolving credit facility was terminated. On May 9, 2012, FET drew the entire amount to repay $171.3 million of short-term borrowings and to pay $3.2 million in expenses related to the closing. The balance was invested in the unregulated money pool. On May 10, 2012, FE repaid $1.0 billion under the existing $2.0 billion facility. Additionally, FirstEnergy and FES/AE Supply amended their existing $2.0 billion and $2.5 billion revolving credit facilities, respectively. The termination date on both facilities was extended from June 2016 to May 2017 and pricing was reduced to reflect current market conditions.

On August 1, 2012, FGCO mandatorily repurchased approximately $106.5 million of 4.75% PCRBs, which it is holding for future remarketing or refinancing subject to market and other conditions.

FIRSTENERGY’S BUSINESS

During the second quarter of 2012, FirstEnergy successfully completed the integration of AE into its IT business networks and financial systems. An important element of this system integration was the capability to modify the segment reporting to reflect how management now views and makes investment decisions regarding the distribution and transmission operations of FirstEnergy. The external segment reporting is now consistent with the internal financial reports used by FirstEnergy's chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. Disclosures for FirstEnergy's operating segments for 2011 have been reclassified to conform to the current presentation.

The key changes in FirstEnergy's reportable segments during the second quarter of 2012 consisted principally of including the federally-regulated transmission assets and operations of JCP&L, ME, PN, MP, PE and WP, that were previously reported within the Regulated Distribution segment, with the renamed Regulated Transmission Segment. There were no changes to the Competitive Energy Services or Other / Corporate Segments. FirstEnergy continues to have three reportable operating segments — Regulated Distribution, Regulated Transmission and Competitive Energy Services.

Financial information for each of FirstEnergy’s reportable segments is presented in the tables below, which includes financial results for the Allegheny subsidiaries beginning February 25, 2011. FES, OE and JCP&L do not have separate reportable operating segments.

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately 6 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 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.

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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 11, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. Results of operations for the six months ended June 30, 2011, include only four months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for variance reporting and analysis. In addition, Allegheny's results were affected by many of the same factors that influenced the operating results of the pre-merger companies. A reconciliation of segment financial results is provided in Note 11, Segment Information, to the Combined Notes to Consolidated Financial Statements. Earnings available to FirstEnergy by business segment were as follows:

	Three Months Ended June 30			Six Months Ended June 30		
	2012	2011	Increase (Decrease)	2012	2011	Increase
	(In millions, except per share data)					
Earnings (Loss) By Business Segment:						
Regulated Distribution	$161	$171	$(10)	$318	$267	$51
Competitive Energy Services	25	21	4	166	36	130
Regulated Transmission	52	57	(5)	112	80	32
Other and reconciling adjustments (1)	(51)	(46)	(5)	(103)	(128)	25
Earnings available to FirstEnergy Corp.	$187	$203	$(16)	$493	$255	$238
Basic Earnings Per Share	$0.45	$0.48	$(0.03)	$1.18	$0.67	$0.51
Diluted Earnings Per Share	$0.45	$0.48	$(0.03)	$1.18	$0.67	$0.51

(1) Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses, noncontrolling interests and the elimination of intersegment transactions.

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Second Quarter 2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,059	$—	$1,527	$1	$3,587
Other	36	184	89	(27)	282
Internal	—	—	209	(209)	—
Total Revenues	2,095	184	1,825	(235)	3,869
Operating Expenses:					
Fuel	57	—	598	1	656
Purchased power	895	—	470	(209)	1,156
Other operating expenses	393	41	513	(33)	914
Provision for depreciation	151	31	103	7	292
Amortization (deferral) of regulatory assets, net	64	(2)	—	—	62
General taxes	167	9	49	7	232
Total Operating Expenses	1,727	79	1,733	(227)	3,312
Operating Income	368	105	92	(8)	557
Other Income (Expense):					
Investment income	19	—	6	(12)	13
Interest expense	(135)	(23)	(71)	(45)	(274)
Capitalized interest	3	1	12	3	19
Total Other Expense	(113)	(22)	(53)	(54)	(242)
Income Before Income Taxes	255	83	39	(62)	315
Income taxes	94	31	14	(12)	127
Net Income	161	52	25	(50)	188
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$161	$ 52	$25	$(51)	$ 187

Second Quarter 2011 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,352	$—	$1,394	$—	$3,746
Other	57	182	101	(38)	302
Internal	—	—	318	(306)	12
Total Revenues	2,409	182	1,813	(344)	4,060
Operating Expenses:					
Fuel	73	—	561	1	635
Purchased power	1,145	—	381	(306)	1,220
Other operating expenses	402	30	625	8	1,065
Provision for depreciation	145	26	109	7	287
Amortization of regulatory assets, net	87	2	—	1	90
General taxes	177	10	51	4	242
Total Operating Expenses	2,029	68	1,727	(285)	3,539
Operating Income	380	114	86	(59)	521
Other Income (Expense):					
Investment income	25	—	16	(10)	31
Interest expense	(136)	(25)	(80)	(24)	(265)
Capitalized interest	2	1	11	6	20
Total Other Expense	(109)	(24)	(53)	(28)	(214)
Income Before Income Taxes	271	90	33	(87)	307
Income taxes	100	33	12	(31)	114
Net Income	171	57	21	(56)	193
Loss attributable to noncontrolling interest	—	—	—	(10)	(10)
Earnings Available to FirstEnergy Corp.	$171	$57	$21	$(46)	$203

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Changes Between Second Quarter 2012 and Second Quarter 2011 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(293)	$—	$133	$1	$(159)
Other	(21)	2	(12)	11	(20)
Internal	—	—	(109)	97	(12)
Total Revenues	(314)	2	12	109	(191)
Operating Expenses:					
Fuel	(16)	—	37	—	21
Purchased power	(250)	—	89	97	(64)
Other operating expenses	(9)	11	(112)	(41)	(151)
Provision for depreciation	6	5	(6)	—	5
Amortization (deferral) of regulatory assets, net	(23)	(4)	—	(1)	(28)
General taxes	(10)	(1)	(2)	3	(10)
Total Operating Expenses	(302)	11	6	58	(227)
Operating Income	(12)	(9)	6	51	36
Other Income (Expense):					
Investment income	(6)	—	(10)	(2)	(18)
Interest expense	1	2	9	(21)	(9)
Capitalized interest	1	—	1	(3)	(1)
Total Other Expense	(4)	2	—	(26)	(28)
Income Before Income Taxes	(16)	(7)	6	25	8
Income taxes	(6)	(2)	2	19	13
Net Income	(10)	(5)	4	6	(5)
Income attributable to noncontrolling interest	—	—	—	11	11
Earnings Available to FirstEnergy Corp.	$(10)	$(5)	$4	$(5)	$(16)

Regulated Distribution — Second Quarter 2012 Compared with Second Quarter 2011
Net income decreased by $10 million in the second quarter of 2012 compared to the same period of 2011, primarily due to reduced revenues, partially offset by decreased purchased power costs and other operating expenses in the second quarter of 2012.
Revenues —
The $314 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2012 (In millions)	2011	Increase (Decrease)
Distribution services	$936	$966	$(30)
Generation sales:			
Retail	961	1,166	(205)
Wholesale	86	172	(86)
Total generation sales	1,047	1,338	(291)
Transmission	61	41	20
Other	51	64	(13)
Total Revenues	$2,095	$2,409	$(314)

The decrease in distribution services revenue primarily reflected the suspension of Ohio's deferred distribution cost recovery rider in December 2011 and an NJBPU-approved reduction to the JCP&L NUG Rider which became effective on March 1, 2012, partially offset by a PAPUC-approved increase to the ME and PN NUG Rider which also became effective on March 1, 2012. Distribution deliveries increased by 0.9% in the second quarter of 2012 from the same period of 2011. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended June 30 2012 (in thousands)	2011	Increase (Decrease)
Residential	11,832	11,958	(1.1)%
Commercial	10,564	10,460	1.0%
Industrial	12,784	12,433	2.8%
Other	151	149	1.3%
Total Electric Distribution MWH Deliveries	35,331	35,000	0.9%

Lower deliveries to residential customers reflect declining average customer consumption and slightly reduced residential accounts. Commercial class deliveries increased due to load growth in the sector. In the industrial sector, MWH deliveries increased by 2.8% primarily due to increased deliveries of 4% to steel customers, 2% to automotive customers and 2% to petroleum customers, partially offset by a 3% decrease in deliveries to chemical customers.

The following table summarizes the price and volume factors contributing to the $291 million decrease in generation revenues in the second quarter of 2012 compared to the same period of 2011:

Source of Change in Generation Revenues	Decrease (In millions)
Retail:	
Effect of decrease in sales volumes	$(152)
Change in prices	(53)
	(205)
Wholesale:	
Effect of decrease in sales volumes	(62)
Change in prices	(24)
	(86)
Decrease in Generation Revenues	$(291)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during the second quarter of 2012, compared with the same period of 2011. This increase in customer shopping is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 79% from 77% for the Ohio Companies, 65% from 53% for the Pennsylvania Companies and 51% from 45% for JCP&L.

The decrease in wholesale generation revenues of $86 million in the second quarter of 2012 was a result of the expiration of a NUG contract in August 2011 and lower PJM market prices.

Transmission revenues increased $20 million primarily due to the implementation of Ohio's NMB transmission rider in June of 2011, which recovers network integration transmission service charges as described below, partially offset by lower RTO revenue resulting from decreased congestion prices.

Other revenue decreased $13 million primarily due to the absence in 2012 of revenue from the sale of certain pole attachment lease rights in June 2011.

Operating Expenses —

Total operating expenses decreased by $302 million due to the following:

- Fuel expense decreased by $16 million primarily due to lower generation output from the Fort Martin power station.

- Purchased power costs were $250 million lower in the second quarter of 2012 primarily due to increased customer shopping, which reduced purchased power requirements, and lower purchased power prices resulting from lower auction prices during the second quarter of 2012 compared to the same period of 2011.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$(103)
Change due to decreased volumes	(111)
	(214)
Purchases from FES:	
Change due to decreased unit costs	(11)
Change due to decreased volumes	(99)
	(110)
Decrease in costs deferred	74
Net Decrease in Purchased Power Costs	$(250)

- Transmission expenses increased $23 million during the second quarter of 2012 compared to the same period of 2011, primarily due to network integration transmission service expenses that, prior to June 2011, were incurred by the generation supplier, and are now being recovered through the NMB transmission rider discussed above, partially offset by lower

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congestion costs.

- Depreciation expense increased $6 million primarily due to higher asset removal costs incurred by JCP&L.
- Regulatory asset amortization expense decreased $23 million due to the following:

The scheduled suspension of the rider recovery of deferred distribution costs in December 2011,
The completion of JCP&L's NUG deferred cost recovery,

Partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011, and increased recovery of energy efficiency expenses.

- General taxes decreased by $10 million primarily due a decrease in gross receipts taxes partially offset by an increase in property taxes.
- Regulated generation operation and maintenance expenses decreased by $6 million primarily due to the upcoming anticipated plant deactivations.
- Expenses related to storm activity decreased $12 million in the second quarter of 2012 compared to the same period in 2011.
- Expenses were further decreased by $15 million due to synergies achieved in connection with the Allegheny merger.

Other Expense —

Other expense increased $4 million in the second quarter of 2012 primarily due to lower investment income on OE's and TE's NDT assets.

Regulated Transmission — Second Quarter 2012 Compared with Second Quarter 2011

Net income decreased by $5 million in the second quarter of 2012 compared to the same period of 2011 primarily due to increased operating expenses.

Revenues —

Total revenues increased by $2 million primarily due to a higher TrAIL rate base.

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

Revenues by	Three Months Ended June 30		
Transmission Asset Owner	2012	2011	Increase
	(In millions)		
ATSI	$54	$54	$—
TrAIL	49	47	2
PATH	4	4	—
Utilities	77	77	—
Total Revenues	$184	$182	$2

Operating Expenses —

Total operating expenses increased by $11 million due to the following:

- Operation and maintenance expenses increased by $11 million primarily due to increased vegetation management costs resulting from additional miles trimmed in second quarter of 2012 compared to the same period in 2011.
- Depreciation expense increased by $5 million primarily due to the TrAIL project in-servicing during May 2011.
- Net amortization of regulatory assets expense decreased by $4 million primarily due to the completion in May 2011 of ATSI's deferred vegetation management cost recovery.

Other Expense —
Other expense decreased $2 million in the second quarter of 2012 due to lower net interest expense, related to the refinancing of the transmission credit facility.

Competitive Energy Services — Second Quarter 2012 Compared with Second Quarter 2011
Net income increased by $4 million in the second quarter of 2012, compared to the same period of 2011, due to higher retail revenues partially offset by increased operating expenses.
Revenues —
Total revenues increased by $12 million in the second quarter of 2012 primarily due to growth in direct and governmental aggregation and wholesale sales, partially offset by a decline in net POLR and structured sales. Revenues were also adversely impacted by lower unit prices compared to the second quarter of 2011.
The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2012	2011	Increase (Decrease)	
	(In millions)			
Direct and Governmental Aggregation	$1,055	$951	$104	
POLR and Structured Sales	295	416	(121	)
Wholesale	386	333	53	
Transmission	42	62	(20	)
RECs	—	12	(12	)
Other	47	39	8	
Total Revenues	$1,825	$1,813	$12	

MWH Sales by Type of Service	Three Months Ended June 30 2012	2011	Increase (Decrease)	
	(In thousands)			
Direct	13,937	11,972	16.4	%
Governmental Aggregation	4,744	3,970	19.5	%
POLR and Structured Sales	5,379	6,733	(20.1	)%
Wholesale	4,846	5,006	(3.2	)%
Total MWH Sales	28,906	27,681	4.4	%

The increase in combined direct and governmental aggregation revenues of $104 million resulted from the acquisition of new residential, commercial and industrial customers. Our customer base increased to 2.0 million industrial, commercial and residential customers as of June 2012 as compared to 1.7 million in June 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers given declining market prices.
The decrease in combined POLR and structured revenues of $121 million was due primarily to lower sales volumes for POLR sales to the Ohio Companies, ME and PN due to an increased migration of customers away from their default service. Revenues were also adversely impacted by lower unit prices. The decline in POLR sales reflects a continued focus on other sales channels by FES.
Wholesale revenues increased $53 million due to increased gains of $147 million on financially settled contracts, which were offset by a $45 million decrease in capacity revenues resulting from the lower capacity prices in the RTO zone effective June 1, 2012, and a $49 million decrease in short-term (net hourly positions) transactions.

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

Source of Change in Direct and Governmental Aggregation	Increase (Decrease)	
	(In millions)	
Direct and Governmental Aggregation:		
Effect of increase in sales volumes	$165	
Change in prices	(61	)
	$104	

Source of Change in POLR and Structured Revenues	Increase (Decrease)	
	(In millions)	
POLR and Structured:		
Effect of decrease in sales volumes	$(84	)
Change in prices	(37	)
	$(121	)

Source of Change in Wholesale Revenues	Increase (Decrease)	
	(In millions)	
Wholesale:		
Effect of decrease in sales volumes	$(7	)
Change in prices	(42	)
Gain on settled contracts	147	
Capacity revenue	(45	)
	$53	

Transmission revenues decreased by $20 million primarily due to lower congestion revenue.

Operating Expenses —

Total operating expenses increased by $6 million in the second quarter of 2012 due to the following:

- Fuel costs increased $37 million primarily due to higher volumes consumed ($30 million) and higher unit prices ($7 million). Volumes increased due to higher fossil generation as a result of fewer planned and unplanned outages.
- Purchased power costs increased $89 million due to higher volumes ($41 million) and losses on settled contracts ($133 million), partially offset by reduced capacity expenses ($21 million) and lower unit prices ($64 million). The increase in purchased power volume primarily relates to the overall increase in direct and governmental aggregation sales volumes and economic purchases.
- Fossil operating costs decreased by $22 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned outages, partially offset by severance costs associated with certain fossil units to be deactivated.
- Nuclear operating costs increased by $21 million due primarily to higher contractor and materials and equipment costs. The second quarter of 2012 included refueling outages at Davis Besse and Beaver Valley Unit 1, whereas the second quarter of 2011 included a refueling outage at Perry and the conclusion of the Beaver Valley 2 refueling outage that began in the first quarter of 2011.
- Transmission expenses decreased by $71 million due to lower congestion, network and loss expenses.
- General taxes decreased by $2 million due to lower property taxes, partially offset by increases in revenue-related taxes.
- Depreciation expense decreased by $6 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with slightly reduced depreciation rates that reflect a periodic study that updated estimated economic lives for certain fossil units.
- Other operating expenses decreased by $40 million primarily due to favorable mark-to-market adjustments on commodity

contract positions.

Other Expense —

Total other expense in the second quarter of 2012 was flat compared to the second quarter of 2011. Reduced interest expense was offset by lower investment income from the nuclear decommissioning trusts.

Other — Second Quarter of 2012 Compared with Second Quarter of 2011

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $5 million decrease in earnings available to FirstEnergy Corp. in the second quarter of 2012 compared to the same period of 2011. The decrease resulted primarily from increased net interest expense ($24 million) and increased income attributable to noncontrolling interest ($11 million) relating to Global Holding, which was de-consolidated in the fourth quarter of 2011, partially offset by lower operating expenses ($41 million) due to lower merger-related costs.

Summary of Results of Operations — First Six Months of 2012 Compared with the First Six Months of 2011

Financial results for FirstEnergy's business segments in the first six months of 2012 and 2011 were as follows:

First Six Months 2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,329	$ —	$3,058	$1	$7,388
Other	91	370	164	(68)	557
Internal	—	—	477	(475)	2
Total Revenues	4,420	370	3,699	(542)	7,947
Operating Expenses:					
Fuel	97	—	1,100	—	1,197
Purchased power	1,977	—	1,000	(474)	2,503
Other operating expenses	828	66	922	(90)	1,726
Provision for depreciation	297	61	203	16	577
Amortization of regulatory assets, net	138	—	—	(1)	137
General taxes	356	21	110	17	504
Total Operating Expenses	3,693	148	3,335	(532)	6,644
Operating Income	727	222	364	(10)	1,303
Other Income (Expense):					
Investment income	42	1	12	(31)	24
Interest expense	(269)	(46)	(136)	(69)	(520)
Capitalized interest	5	1	23	7	36
Total Other Expense	(222)	(44)	(101)	(93)	(460)
Income Before Income Taxes	505	178	263	(103)	843
Income taxes	187	66	97	(1)	349
Net Income	318	112	166	(102)	494
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$318	$ 112	$166	$(103)	$ 493

First Six Months 2011 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,527	$ —	$2,556	$—	$ 7,083
Other	105	295	180	(71)	509
Internal	—	—	661	(617)	44
Total Revenues	4,632	295	3,397	(688)	7,636
Operating Expenses:					
Fuel	97	—	991	—	1,088
Purchased power	2,323	—	700	(617)	2,406
Other operating expenses	753	58	1,256	(9)	2,058
Provision for depreciation	258	45	197	12	512
Amortization of regulatory assets, net	215	5	—	2	222
General taxes	353	19	95	12	479
Total Operating Expenses	3,999	127	3,239	(600)	6,765
Operating Income	633	168	158	(88)	871
Other Income (Expense):					
Investment income	48	—	21	(17)	52
Interest expense	(259)	(42)	(144)	(51)	(496)
Capitalized interest	3	1	22	12	38
Total Other Expense	(208)	(41)	(101)	(56)	(406)
Income Before Income Taxes	425	127	57	(144)	465
Income taxes	158	47	21	(1)	225
Net Income	267	80	36	(143)	240
Loss attributable to noncontrolling interest	—	—	—	(15)	(15)
Earnings Available to FirstEnergy Corp.	$267	$ 80	$36	$(128)	$ 255

Changes Between First Six Months 2012 and First Six Months 2011 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(198)	$ —	$ 502	$ 1	$ 305
Other	(14)	75	(16)	3	48
Internal	—	—	(184)	142	(42)
Total Revenues	(212)	75	302	146	311
Operating Expenses:					
Fuel	—	—	109	—	109
Purchased power	(346)	—	300	143	97
Other operating expenses	75	8	(334)	(81)	(332)
Provision for depreciation	39	16	6	4	65
Amortization of regulatory assets, net	(77)	(5)	—	(3)	(85)
General taxes	3	2	15	5	25
Total Operating Expenses	(306)	21	96	68	(121)
Operating Income	94	54	206	78	432
Other Income (Expense):					
Investment income	(6)	1	(9)	(14)	(28)
Interest expense	(10)	(4)	8	(18)	(24)
Capitalized interest	2	—	1	(5)	(2)
Total Other Expense	(14)	(3)	—	(37)	(54)
Income Before Income Taxes	80	51	206	41	378
Income taxes	29	19	76	—	124
Net Income	51	32	130	41	254
Income attributable to noncontrolling interest	—	—	—	16	16
Earnings Available to FirstEnergy Corp.	$ 51	$ 32	$ 130	$ 25	$ 238

Regulated Distribution — First Six Months of 2012 Compared to First Six Months of 2011
Net income increased by $51 million in the first six months of 2012 compared to the same period of 2011, primarily due to earnings from the Allegheny Utilities and lower merger-related costs, partially offset by decreased weather-related customer usage in the first six months of 2012.
Results of operations for the six months ended June 30, 2011, include only four months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for variance reporting and analysis.
Revenues —
The $212 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
Pre-merger companies:			
Distribution services	$1,541	$1,721	$(180)
Generation sales:			
Retail	1,300	1,620	(320)
Wholesale	95	220	(125)
Total generation sales	1,395	1,840	(445)
Transmission	90	11	79
Other	80	93	(13)
Total pre-merger companies	3,106	3,665	(559)
Allegheny Utilities[(1)]	1,314	967	347
Total Revenues	$4,420	$4,632	$(212)

(1) Allegheny results include 6 months in 2012 and 4 months in 2011.

The decrease in distribution services revenue for the pre-merger companies reflects lower distribution deliveries (described below), the suspension of Ohio's deferred distribution cost recovery rider in December 2011 and an NJBPU-approved reduction to the JCP&L NUG Rider which became effective on March 1, 2012, partially offset by a PAPUC-approved increase to the ME and PN NUG Rider which also became effective on March 1, 2012. Distribution deliveries (excluding the Allegheny Utilities) decreased by 1.3% in the first six months of 2012 from the same period of 2011. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In thousands)		
Pre-merger companies:			
Residential	18,294	19,288	(5.2)%
Commercial	15,777	15,882	(0.7)%
Industrial	18,071	17,640	2.4%
Other	248	256	(3.1)%
Total pre-merger companies	52,390	53,066	(1.3)%
Allegheny Utilities[(1)]	20,137	13,068	54.1%
Total Electric Distribution MWH Deliveries	72,527	66,134	9.7%

(1) Allegheny results include 6 months in 2012 and 4 months in 2011.

Lower deliveries to residential and commercial customers for the pre-merger companies reflect decreased weather-related usage resulting from heating degree days that were 21% below 2011 levels, partially offset by cooling degree days that were 9% higher than 2011 levels. In the industrial sector, MWH deliveries increased 3% to steel customers and 3% to automotive customers, partially offset by a decrease of 1% to petroleum customers and 2% to chemical customers.

The following table summarizes the price and volume factors contributing to the $445 million decrease in generation revenues for the pre-merger companies in the first six months of 2012 compared to the same period of 2011:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)	
Retail:		
Effect of decrease in sales volumes	$(328	)
Change in prices	8	
	(320	)
Wholesale:		
Effect of decrease in sales volumes	(87	)
Change in prices	(38	)
	(125	)
Net Decrease in Generation Revenues	$(445	)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories in the first six months of 2012, compared with the same period of 2011. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 78% from 75% for the Ohio Companies, 63% from 48% for ME's, PN's and Penn's service areas and 50% from 43% for JCP&L.

The decrease in wholesale generation revenues of $125 million in the first six months of 2012 was a result of the expiration of a NUG contract in August 2011 and lower PJM market prices.

Transmission revenues increased $79 million primarily due to the implementation of Ohio's NMB transmission rider in June of 2011, which recovers network integration transmission service charges as described further below.

Operating Expenses —

Total operating expenses decreased by $306 million due to the following:

- Purchased power costs, excluding the Allegheny Utilities, were $526 million lower in the first six months of 2012 due primarily to a decrease in volumes required from increased customer shopping and the impact of milder weather.

Source of Change in Purchased Power	Increase (Decrease) (In millions)	
Pre-merger companies:		
Purchases from non-affiliates:		
Change due to decreased unit costs	$(83	)
Change due to decreased volumes	(300	)
	(383	)
Purchases from FES:		
Change due to decreased unit costs	(27	)
Change due to decreased volumes	(167	)
	(194	)
Decrease in costs deferred	51	
Total pre-merger companies	(526	)
Purchases by Allegheny Utilities	180	
Net Decrease in Purchased Power Costs	$(346	)

- Transmission expenses increased $96 million during the first six months of 2012 compared to the same period of 2011. The increase is primarily due to network integration transmission service expenses that, prior to June 2011, were incurred by the generation supplier, and are now being recovered through the NMB transmission rider referred to above.
- Regulatory assets amortization expense decreased $85 million due to the following:

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The scheduled suspension of the rider recovering deferred distribution costs in December 2011,
The completion of JCP&L's NUG deferred cost recovery,
Partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011.

- Energy Efficiency program costs, which are recovered through rates, increased by $24 million.
- General taxes decreased by $17 million primarily due to a decrease in gross receipts taxes for ME, PN and JCP&L.
- Depreciation expense increased by $11 million primarily due to higher asset removal costs incurred by JCP&L.
- Other costs decreased due to the absence of a provision for excess and obsolete material of $13 million that was recognized in the first quarter of 2011 relating to revised inventory practices adopted in conjunction with the Allegheny merger.
- Merger-related costs decreased $54 million in the first six months of 2012 compared to the same period of 2011.

Operating Expenses - Allegheny[1]	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
Purchased Power	$653	$473	$180
Fuel	97	97	—
Transmission	68	51	17
Amortization of regulatory assets, net	(5)	(13)	8
Other operating expenses	24	8	16
General Taxes	68	48	20
Depreciation Expense	85	57	28
Total Operating Expenses	$990	$721	$269

(1) Allegheny results include 6 months in 2012 and 4 month in 2011.

Other Expense —

Other expense increased $14 million in the first six months of 2012 primarily due to net interest expense on debt of the Allegheny Utilities.

Regulated Transmission — First Six Months of 2012 Compared with First Six Months of 2011

Net income increased by $32 million in the first six months of 2012 compared to the same period of 2011 primarily due to earnings associated with TrAIL, PATH and the Allegheny Utilities' transmission assets that were acquired in the merger.

Revenues —

Total revenues increased by $75 million principally due to revenues from TrAIL, PATH and the Allegheny Utilities' transmission assets.

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

Revenues by Transmission Asset Owner	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
ATSI	$107	$106	$1
TrAIL[1]	102	61	41
PATH[1]	7	5	2
Utilities[1]	154	123	31
Total Revenues	$370	$295	$75

(1) Allegheny results include 6 months in 2012 and 4 months in 2011.

Operating Expenses —
Total operating expenses increased by $21 million principally due to the addition of TrAIL, PATH and the Allegheny Utilities' transmission operating expenses for six months in 2012 compared to four months in 2011, partially offset by reduced regulatory asset amortization expense due to the completion in May 2011 of ATSI's deferred vegetation management cost recovery.
Other Expense —
Other expense increased by $3 million in the first six months of 2012 due to a full six months of TrAIL interest expense compared to four months in 2011.

Competitive Energy Services — First Six Months of 2012 Compared with First Six Months of 2011
Net income increased by $130 million in the first six months of 2012, compared to the same period of 2011, due to higher retail revenues and the inclusion of the results of the Allegheny companies, partially offset by higher operating expenses.
Revenues —
Total revenues increased by $302 million in the first six months of 2012 primarily due to growth in direct and governmental aggregation and wholesale sales and the inclusion of the Allegheny companies for six months in 2012 compared to four months in 2011, partially offset by a net decline in POLR and structured sales. Revenues were also adversely impacted by lower unit prices compared to the first six months of 2011.
The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
Pre-merger Companies:			
Direct and Governmental Aggregation	$2,040	$1,765	$275
POLR and Structured Sales	426	607	(181)
Wholesale[1]	259	156	103
Transmission	60	56	4
RECs	5	44	(39)
Other	76	79	(3)
Allegheny companies[2]	833	690	143
Total Revenues	$3,699	$3,397	$302
Allegheny companies[2]			
Direct and Governmental Aggregation	$46	$34	$12
POLR and Structured Sales	248	254	(6)
Wholesale	511	357	154
Transmission	28	44	(16)
Other	—	1	(1)
Total Revenues	$833	$690	$143

(1) Excludes $128 million in intra-segment sales by AE Supply to FES
(2) Allegheny results include 6 months in 2012 and 4 months in 2011.

MWH Sales by Type of Service	Six Months Ended June 30 2012	2011	Increase (Decrease)	
	(In thousands)			
Pre-merger Companies:				
Direct	25,954	21,219	22.3	%
Governmental Aggregation	9,930	8,279	19.9	%
POLR and Structured Sales	7,645	9,561	(20.0	)%
Wholesale	86	1,380	(93.8	)%
Allegheny companies(1)	13,406	10,687	25.4	%
Total MWH Sales	57,021	51,126	11.5	%
Allegheny companies(1)				
Direct and Governmental Aggregation	762	570	33.7	%
POLR	4,098	2,981	37.5	%
Structured Sales	279	1,149	(75.7	)%
Wholesale	8,267	5,987	38.1	%
Total MWH Sales	13,406	10,687	25.4	%

(1) Allegheny results include 6 months in 2012 and 4 months in 2011.

The increase in combined direct and governmental aggregation revenues of $275 million resulted from the acquisition of new residential, commercial and industrial customers. Our customer base increased to 2.0 million industrial, commercial and residential customers as of June 2012 as compared to 1.7 million in June 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers.

The decrease in combined POLR and structured revenues of $181 million was due primarily to lower sales volumes to the Ohio Companies, ME and PN. Revenues were also adversely impacted by lower unit prices, discussed above, which were partially offset by increased structured sales. The decline in POLR sales reflects a continued focus on other sales channels.

Wholesale revenues increased $103 million due to increased gains of $100 million on financially settled contracts and a $42 million increase in capacity revenues. These increases were partially offset by decreased volumes sold of $39 million.

The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

Source of Change in Direct and Governmental Aggregation	Increase (Decrease)	
	(In millions)	
Direct and Governmental Aggregation:		
Effect of increase in sales volumes	$381	
Change in prices	(106	)
	$275	

Source of Change in POLR and Structured Revenues	Increase (Decrease)	
	(In millions)	
POLR and Structured:		
Effect of decrease in sales volumes	$(122	)
Change in prices	(59	)
	$(181	)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(39)
Change in prices	—
Gain on settled contracts	100
Capacity revenue	42
	$103

Operating Expenses —

Total operating expenses for the pre-merger companies increased by $95 million in the first six months of 2012 due to the following:

- Fuel costs increased $38 million primarily due to higher unit prices ($29 million) and higher volumes consumed ($9 million). Volumes increased due to higher nuclear generation, partially offset by lower generation from the fossil units.
- Purchased power costs increased $295 million due to higher volumes ($147 million), loss on settled contracts ($229 million) and increased capacity expense ($61 million), partially offset by lower unit prices ($142 million). The increase in purchased power volumes primarily relates to the overall increase in direct and governmental aggregation sales volumes and economic purchases.
- Fossil operating costs decreased by $16 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned outages, partially offset by severance costs associated with certain fossil units to be deactivated.
- Nuclear operating costs decreased by $8 million due primarily to lower labor, materials and equipment costs. During the first six months of 2012, there were refueling outages at Davis Besse and Beaver Valley Unit 1 compared to 2011, which included refueling outages at Perry and Beaver Valley Unit 2. Total outage days were reduced in the first six months of 2012 compared to the same period of 2011.
- Transmission expenses decreased $89 million due primarily to lower congestion, network and line loss costs, partially offset by higher ancillary costs.
- General taxes increased by $4 million primarily due to an increase in revenue-related taxes.
- Depreciation expense decreased $15 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with slightly reduced depreciation rates that reflect a periodic study that updated estimated economic lives for certain fossil assets and credits resulting from a settlement with the DOE regarding storage of spent nuclear fuel.
- Other operating expenses decreased by $114 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($64 million) and reduced costs associated with the merger ($14 million). In addition, 2011 expenses included a $54 million provision for excess and obsolete material relating to revised inventory practices adopted in connection with the Allegheny merger and a $20 million impairment charge related to non-core assets. These decreases were partially offset by increases in other expenses of $38 million associated with inter-segment leases, and labor, agent fees and professional and contractor costs associated with our retail business.

The Allegheny companies' operations for six months in 2012 and four months in 2011 added $720 million and $719 million to operating expenses, respectively, as shown in the following table:

Operating Expenses (Credits) - Allegheny[1]	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
Fuel	$391	$320	$71
Purchased power	79	74	5
Fossil generation	88	82	6
Transmission	63	99	(36)
Other operating expenses	23	43	(20)
Mark-to-market adjustments	(16)	43	(59)
General taxes	28	15	13
Depreciation	64	43	21
Total Operating Expense	$720	$719	$1

(1) Allegheny results include 6 months in 2012 and 4 months in 2011.

Other Expense —

Total other expense in the first six months of 2012 was flat compared to the first six months of 2011. Reduced net interest expense from debt reductions in 2011 was offset by lower investment income from the nuclear decommissioning trusts.

Other — First Six Months of 2012 Compared with First Six Months of 2011

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $25 million increase in earnings available to FirstEnergy Corp. in the first six months of 2012 compared to the same period of 2011. The increase resulted primarily from decreased other operating expenses ($81 million) due to lower merger-related costs, partially offset by increased net interest expenses ($23 million), decreased investment income ($14 million) and decreased income attributable to noncontrolling interest ($16 million) relating to Global Holding, which was de-consolidated in the fourth quarter of 2011.

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 tables provide information about the composition of net regulatory assets as of June 30, 2012 and December 31, 2011, and the changes during the six months ended June 30, 2012:

Regulatory Assets by Source	June 30, 2012	December 31, 2011	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$297	$309	$(12)
Customer receivables for future income taxes	490	519	(29)
Nuclear decommissioning and spent fuel disposal costs	(215)	(210)	(5)
Asset removal costs	(375)	(347)	(28)
Deferred transmission costs	392	340	52
Deferred generation costs	334	400	(66)
Deferred distribution costs	249	267	(18)
Contract valuations	516	299	217

Other	434	453	(19)
Total	$2,122	$2,030	$92

FirstEnergy had $437 million of net regulatory liabilities as of June 30, 2012, that are primarily related to asset removal costs. Regulatory assets that do not earn a current return totaled approximately $315 million as of June 30, 2012. JCP&L had $118 million of regulatory assets not earning a current return, which include certain storm damage costs and pension and OPEB benefits that are expected to be recovered by 2026. The remaining $197 million of regulatory assets include certain PJM transmission and regulatory transition costs, which are expected to be recovered by 2020.

CAPITAL RESOURCES AND LIQUIDITY

As of June 30, 2012, FirstEnergy had $94 million of cash and cash equivalents and available liquidity of approximately $3.6 billion. 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 the remainder of 2012 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.

As of June 30, 2012, FirstEnergy's net deficit in working capital (current assets less current liabilities) was principally due to currently payable long-term debt, which, as of June 30, 2012, included the following:

Currently Payable Long-term Debt	(In millions)
PCRBs supported by bank LOCs [1]	$713
Term loan	150
Unsecured notes	150
Unsecured PCRBs [1]	317
Secured PCRBs [1]	106
Collateralized lease obligation bonds	71
Sinking fund requirements	54
Other notes	16
	$1,577

(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 approximately $1.9 billion of short-term borrowings as of June 30, 2012, and no significant short-term borrowings as of December 31, 2011. FirstEnergy's available liquidity as of June 30, 2012, is summarized in the following table:

Company	Type	Maturity	Commitment (In millions)	Available Liquidity
FirstEnergy[1]	Revolving	May 2017	$2,000	$1,080
FES / AE Supply	Revolving	May 2017	2,500	2,498
FET[2]	Revolving	May 2017	1,000	—
AGC	Revolving	Dec 2013	50	—
		Subtotal	$5,550	$3,578
		Cash	—	63
		Total	$5,550	$3,641

(1) FirstEnergy Corp. 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 $5.5 billion (Facilities). The Facilities consist of a $2.0 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2017, unless the lenders agree, at the request of the applicable borrowers, to up to two additional one-year extensions. 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 of no more than 65%, and 70% 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 well as the debt to total capitalization ratios (as defined under each of the Facilities) as of June 30, 2012:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations		Debt to Capitalization
	(In millions)					
FE	$2,000	$—	$—	$—	(2)	58.8%
FES	—	1,500	—	—	(3)	50.2%
AE Supply	—	1,000	—	—	(3)	34.7%
FET	—	—	1,000	—	(2)	64.4%
OE	500	—	—	500	(4)	61.9%
CEI	500	—	—	500	(4)	62.0%
TE	500	—	—	500	(4)	62.6%
JCP&L	425	—	—	600	(1)(4)	45.6%
ME	300	—	—	500	(1)(4)	54.3%
PN	300	—	—	300	(1)(4)	59.0%
WP	200	—	—	200	(1)(4)	52.7%
MP	150	—	—	150	(1)(4)	54.9%
PE	150	—	—	150	(1)(4)	54.9%
ATSI	—	—	100	100	(4)	48.6%
Penn	50	—	—	50	(1)(4)	41.1%
TrAIL	—	—	200	400	(1)(4)	44.0%

(1) On June 1, 2012 the joint application, which was filed with the FERC on April 11, 2012, seeking authorization to increase or incur short-term debt, was granted.
(2) No limitations.
(3) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
(4) Including amounts which may be borrowed under the regulated companies' money pool.

As of June 30, 2012, FE and its subsidiaries could issue additional debt of approximately $5.7 billion, or recognize a reduction in equity of approximately $3.1 billion, and remain within the limitations of the financial covenants required by the Facilities.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy Facility and $225 million of the FET Facility, subject to each borrower’s sub-limit, is available for the issuance of LOCs 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.

AGC Revolving Credit Facility

A separate $50 million revolving credit facility is available to AGC until December 2013. Under the terms of this credit facility, outstanding debt of AGC may not exceed 65% of the sum of its debt and equity as of the last day of each calendar quarter. This provision limits the debt level of AGC and also limits the net assets of AGC that may be transferred to AE. As of June 30, 2012, the debt to total capitalization ratios for AGC (as defined under this credit facility) was 52% and AGC could issue additional debt of approximately $37 million and remain within the limitations of the financial covenants under this credit facility.

FirstEnergy Money Pools

FirstEnergy’s regulated 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 2012 was 0.65% per annum for the regulated companies' money pool and 1.24% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of June 30, 2012, FirstEnergy's currently payable long-term debt included approximately $713 million ($640 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 were issued by the following banks as of June 30, 2012:

LOC Bank	Aggregate LOC Amount[1] (In millions)	LOC Termination Date	Reimbursements of LOC Draws Due
UBS	$272	April 2014	April 2014
CitiBank N.A.	166	June 2014	June 2014
Wachovia Bank	152	March 2014	March 2014
The Bank of Nova Scotia	49	April 2014	Multiple dates[2]
The Bank of Nova Scotia	82	April 2015	April 2015
Total	$721		

(1) Includes approximately $8 million of applicable interest coverage.

(2) Earlier of 6 months from drawing or the LOC termination date.

Long-Term Debt Capacity

As of June 30, 2012, the Ohio Companies and Penn had the aggregate capacity to issue approximately $2.8 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by the Ohio Companies is also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE to incur additional secured debt not otherwise permitted by a specified exception of up to $139 million. As a result of the indenture provisions, CEI and TE cannot incur any additional secured debt. ME and PN had the capability to issue secured debt of approximately $375 million and $385 million, respectively, under provisions of their senior note indentures as of June 30, 2012. In addition, based upon their net earnings and available bondable property additions as of June 30, 2012, MP, PE and WP had the capacity to issue approximately $1.5 billion of additional FMBs in the aggregate under the terms of their FMB indentures. Additionally, the issuance of FMBs by these companies is subject to compliance with the financial covenants of the Facilities and any required regulatory approvals and may be subject to statutory and/or charter limitations.

The Ohio Companies filed an application with the PUCO for a financing order under the Ohio securitization legislation adopted in December 2011, which we expect will be primarily used to assist the Ohio Companies in their planned debt reductions.

Based upon FGCO's net earnings and available bondable property additions under its FMB indentures as of June 30, 2012, FGCO had the capacity to issue $1.8 billion of additional FMBs under the terms of that indenture. Based upon NGC's net earnings and available bondable property additions under its FMB indenture as of June 30, 2012, NGC had the capacity to issue $2.2 billion of additional FMBs under the terms of that indenture.

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’ debt credit ratings as of June 30, 2012:

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

Changes in Cash Position

As of June 30, 2012, FirstEnergy had $94 million of cash and cash equivalents compared to $202 million of cash and cash equivalents as of December 31, 2011. As of June 30, 2012 and December 31, 2011, FirstEnergy had approximately $68 million and $79 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 primarily by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $62 million during the first six months of 2012 compared with $1,031 million being provided from operating activities during the first six months of 2011, as summarized in the following table:

Operating Cash Flows	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
Net income	$494	$240	$254
Non-cash charges	817	1,201	(384)
Pension trust contributions	(600)	(262)	(338)
Working capital and other	(649)	(148)	(501)
	$62	$1,031	$(969)

The $384 million decrease in non-cash charges and other adjustments is primarily due to the following:

- $129 million from accrued compensation and retirement benefits as a result of higher performance-related incentive compensation payments during the first six months of 2012 compared to the same period of 2011.
- $85 million from lower net amortization of regulatory assets as a result of the suspension of the rider recovering deferred distribution costs in September 2011 and the completion of JCP&L's NUG deferred cost recovery, partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011.
- $175 million from decreased deferred income taxes as a result of a change in bonus depreciation.

The $501 million decrease in cash flows from working capital and other is primarily due to the following:

- $304 million from lower collections from customers during the first six months of 2012 as a result of the effects of milder weather described in Results of Operations above.

- $133 million from increased materials and supplies balances as a result of increased coal inventories and the absence in 2012 of the $67 million non-cash inventory valuation adjustment recorded in connection with the merger.
- $94 million from lower accounts payable balances as a result of the timing of payments to vendors during the first six months of 2012 as compared to the same period of 2011.

Cash Flows From Financing Activities

In the first six months of 2012, cash provided from financing activities was $831 million compared to $1,039 million of net cash used for financing activities during the first six months of 2011. The following tables summarize new debt financing (net of any discounts) and redemptions:

Securities Issued or Redeemed / Retired	Six Months Ended June 30 2012	2011
	(In millions)	
New Issues		
PCRBs	$82	$272
Long-term revolving credit	—	70
FMBs	100	—
Unsecured Notes	—	161
	$182	$503
Redemptions / Retirements		
PCRBs	$82	$312
Long-term revolving credit	—	475
Senior secured notes	81	166
FMBs	—	14
Unsecured notes	583	35
	$746	$1,002
Short-term borrowings, net	$1,890	$(44)

On August 1, 2012, FGCO mandatorily repurchased approximately $106.5 million of 4.75% PCRBs, which it is holding for future remarketing or refinancing subject to market and other conditions.

Cash Flows From Investing Activities

Cash used for investing activities in the first six months of 2012 principally represented cash used for property additions. The following table summarizes investing activities for the first six months of 2012 and the comparable period of 2011:

Cash Used for (Provided from) Investing Activities	Six Months Ended June 30 2012	2011	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated distribution	$443	$381	$62
Regulated transmission	122	170	(48)
Competitive energy services	393	411	(18)
Other and reconciling adjustments	43	56	(13)
Cash received in Allegheny merger	—	(590)	590
Investments	(49)	54	(103)
Other	49	53	(4)
	$1,001	$535	$466

Net cash used for investing activities during the first six months of 2012 increased by $466 million compared to the same period of 2011. The increase was principally due to the absence in 2012 of cash acquired in the Allegheny merger ($590 million), partially offset by a decrease in property additions ($17 million), a decrease in net purchases of investment securities ($66 million) and

additional restricted cash investments ($37 million).
During the remainder of 2012, capital requirements for property additions and capital leases are estimated to be approximately $1.4 billion, including approximately $201 million for nuclear fuel.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could have been required to make under these guarantees as of June 30, 2012, was approximately $4.1 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts(1)	$287
LOC (long-term debt) - interest coverage(2)	5
OVEC obligations	300
Other(3)	296
	888
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	137
LOC (long-term debt) - interest coverage(2)	3
FES' guarantee of NGC's nuclear property insurance	85
FES' guarantee of FGCO's sale and leaseback obligations	2,199
Other	12
	2,436
Signal Peak & Global Rail facility	350
Surety Bonds	221
LOCs(4)	173
	744
Total Guarantees and Other Assurances	$4,068

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $713 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $95 million for nuclear decommissioning funding assurances, $161 million supporting OE's sale and leaseback arrangements, and $32 million for railcar leases.

(4) Includes $32 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $108 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $34 million pledged in connection with the sale and leaseback of Perry by OE.

Of this amount, substantially all relates to guarantees of wholly-owned consolidated entities. FES' debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, and FES guarantees the debt obligations of each of FGCO and NGC. Accordingly, present and future holders of indebtedness of FES, FGCO, and NGC would have claims against each of FES, FGCO and NGC, regardless of whether their primary obligor is FES, FGCO or NGC.

Collateral and Contingent-Related Features

As part of the normal course of business, FirstEnergy and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuels, and emissions allowances. Certain bilateral agreements and derivative instruments contain provisions that require FirstEnergy or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FirstEnergy'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 FES' and AE Supply's power portfolio exposure as of June 30, 2012, FES has posted collateral of $36 million. The Regulated Distribution segment has posted collateral of $9 million.

These credit-risk-related contingent features stipulate that if the subsidiaries 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 and lower, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FirstEnergy or its subsidiaries. The following chart discloses the additional credit contingent contractual obligations as of June 30, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$373	$6	$40	$419
BB+/Ba1 Credit Ratings	$429	$6	$59	$494
Full impact of credit contingent contractual obligations	$658	$73	$73	$804

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of June 30, 2012 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 and AE Supply would be required to post $46 million and $13 million, respectively.

Other Commitments and Contingencies

Signal Peak and Global Rail are borrowers under a $350 million syndicated two-year senior secured term loan facility due in October 2012. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that originally shared ownership in the borrowers with FEV, have provided a guaranty of the borrowers' obligations under the facility. Following the sale of a portion of FEV's ownership interest in Signal Peak and Global Rail in the fourth quarter of 2011, FirstEnergy, WMB Loan Ventures, LLC and WMB Loan Ventures II, LLC, together with Global Mining Group, LLC and Global Holding, continued to guarantee the borrowers' obligations under the current facility. In addition, FEV, Global Mining Group, LLC and Global Holding, the entities that own direct and indirect equity interests in the borrowers, have pledged those interests to the lenders under the current facility as collateral. Global Holding is involved in negotiations to refinance the current facility with a bank facility under which it would be the borrower. In connection with such proposed refinancing, FirstEnergy expects to provide the new lenders with a guarantee of Global Holding's obligations, and FirstEnergy and WMB Marketing Ventures, LLC expect to pledge not less than two-thirds of the equity interests in Global Holding and its subsidiaries.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $1.5 billion as of June 30, 2012, of which $121 million is applicable to the 1987 Bruce Mansfield Plant leases, which may be terminated pursuant to an early buyout option. In March 2012, FGCO, as assignee, provided notice of its irrevocable election of the early buyout option of the 1987 Bruce Mansfield Plant leases. The purchase price to be paid by FGCO will be equal to the higher of the special termination value under the applicable facility leases (in the aggregate approximately $435 million, covering both debt and equity under the leases) and the fair market value. FGCO has reached preliminary agreement with some of the parties on the purchase price and certain other parties have invoked an appraisal process to determine the fair market value. On

August 2, 2012, FGCO completed the acquisition of the equity interest in certain of the 1987 Bruce Mansfield Plant leases with two owner participants totaling approximately $69.4 million. From time to time we also enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. We cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

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 interest rates and 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 6, Fair Value Measurements of the Combined Notes to the Consolidated Financial Statements). Sources of information for the valuation of commodity derivative contracts assets and liabilities as of June 30, 2012 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$3	$—	$—	$—	$—	$—	$3
Other external sources[2]	(100)	(45)	(26)	(27)	—	—	(198)
Prices based on models	4	—	—	—	(22)	(143)	(161)
Total[3]	$(93)	$(45)	$(26)	$(27)	$(22)	$(143)	$(356)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and IntercontinentalExchange, Inc. quotes.
(3) Includes $(438) million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are generally subject to regulatory accounting and do not materially 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, 2012, an adverse 10% change in commodity prices would decrease net income by approximately $2 million during the next 12 months.

Interest Rate Risk

In the second quarter of 2012, FirstEnergy executed a total of $1.6 billion forward starting swap agreements expiring December 31, 2013, with sixteen separate counterparties in order to lock in interest rates on planned debt issuances, which includes refinancings. The total portfolio of swaps carries a weighted average 10-year fixed rate of 2.315%.

Equity Price Risk

As of June 30, 2012, the FirstEnergy pension plan assets were in approximately 21% in equity securities, 52% in fixed income securities, 17% in absolute return strategies, 5% in real estate, 2% in private equity and 3% in cash. 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, 2012, FirstEnergy made a voluntary pre-tax contribution to its qualified pension plans of $600 million. See Note 3, Pensions and Other Postemployment Benefits, to the Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB.

NDT funds have been established to satisfy NGC’s, OE's, JCP&L's and other FE subsidiaries' nuclear decommissioning obligations. As of June 30, 2012, approximately 82% of the funds were invested in fixed income securities, 13% of the funds were invested in equity securities and 5% 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 $1,780 million, $280 million and $100 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2012, excluding $7 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $28 million reduction in fair value as of June 30, 2012. JCP&L's decommissioning trust is subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NGC and OE recognize in earnings the unrealized losses on available-for-sale securities held in their 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 months ended June 30, 2012, approximately $4 million was contributed to OE's NDT. FENOC has submitted a $95 million parental guarantee to the NRC relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry.

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose 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 measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of set-off. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FirstEnergy manages the quality of its portfolio of energy contracts, currently having a weighted average risk rating for energy contract counterparties of BBB (S&P).

Retail Credit Risk

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

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

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

OUTLOOK

STATE REGULATION

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

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 overseen by the MDPSC and a third party monitor. The settlements with respect to residential SOS for PE customers expire on December 31, 2012, but by statute service will continue in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential service have expired but, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. In 2008, PE filed its comprehensive plans for attempting to achieve those goals, asking the MDPSC to approve programs for residential, commercial, industrial, and governmental customers, as well as a customer education program. The MDPSC ultimately approved the programs in August 2009 after certain modifications had been made as required by the MDPSC, and approved cost recovery for the programs in October 2009. Expenditures were estimated to be approximately $101 million for the PE programs for the period of 2009 to 2015 and would be recovered over that six-year period. Maryland law only allows for the utility to recover lost distribution revenue attributable to the 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. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan that includes additional and improved programs for the period 2012-2014. The plan is expected to cost approximately $66 million over the three-year period. The MDPSC held hearings on PE and the other utilities' plans in October 2011, and on December 22, 2011, issued an order approving PE's plan with various modifications and follow-up assignments.

Pursuant to a bill passed by the Maryland legislature, the MDPSC proposed rules, based on the product of a working group of utilities, regulators, and other interested stakeholders, 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 bill requires that the MDPSC consider cost-effectiveness, and provides that the MDPSC may adopt different standards for different utilities based on such factors as system design and existing infrastructure, geography, and customer density. Beginning in July 2013, the MDPSC is required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. Further comments were filed regarding the proposed rules on March 26, 2012, and at a hearing on April 17, 2012, the MDPSC approved re-publication of the rules as final.

NEW JERSEY

JCP&L currently provides BGS for retail customers that do not choose a third party electric generation supplier and for customers of third party electric generation suppliers 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. The most recent BGS auction results, for supply commencing June 1, 2012, were approved by the NJBPU on February 9, 2012.

On September 8, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, affirming the determination made at its July 18, 2012 agenda meeting, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that the Company 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 on or before November 1, 2012. JCP&L is unable to predict the outcome of this matter.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held to solicit comments regarding the state of preparedness and responsiveness of the EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 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 report of the consultant is due to be submitted to the NJBPU in August 2012. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

OHIO

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

- Generation supplied through a CBP commencing June 1, 2011;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million dependent on the outcome of certain PJM proceedings, agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their current ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012.

As approved, the ESP 3 plan will maintain the substantial benefits from the current ESP including:

- Freezing current base distribution rates through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at the levels established in the existing ESP;
- Providing Percentage of Income Payment Plan customers with a 6 percent generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan will provide additional new benefits, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in October 2012 and January 2013, to mitigate any potential price spikes for FirstEnergy Ohio utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing renewable energy credits mandated by SB 221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all FirstEnergy Ohio non-shopping utility customers by spreading out the costs over the entire ESP period.

The filing is supported by 19 parties including: Industrial Energy Users, Ohio Energy Group, PUCO Staff, the City of Akron, Ohio Manufacturers Association, Ohio Partners for Affordable Energy, and the Council of Smaller Enterprises (COSE). Seven additional parties agreed not to oppose the filing.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. Utilities were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018.

In December 2009, the Ohio Companies filed their three-year portfolio plan, as required by SB221, seeking approval for the programs they intended to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. In March 2011, the PUCO issued an Opinion and Order generally approving the Ohio Companies' 2010-2012 portfolio plan which provides for recovery of all costs associated with the programs, including lost revenues. The Ohio Companies have implemented those programs included in the plan. However, due to the timing of the approval of the plan, the Ohio Companies requested that the PUCO amend the energy efficiency and peak demand reduction benchmarks for 2010. On May 19, 2011, the PUCO granted the request to reduce the 2010 energy efficiency and peak demand reductions to the level achieved in 2010 for OE, while finding that the issue was moot for CEI and TE because they achieved their targets in that year. Failure to comply with the benchmarks or to obtain such an amendment may subject the Ohio Companies to an assessment of a penalty by the PUCO.

The Ohio Companies had filed applications for rehearing regarding portions of the PUCO's decision related to the Ohio Companies' three-year portfolio plan, which was later denied. On December 30, 2011, the Ohio Companies filed a notice of appeal with the Supreme Court of Ohio, which was dismissed on June 20, 2012. In accordance with PUCO Rules and a PUCO directive, the Ohio Companies filed their next three-year portfolio plan for the period January 1, 2013 through December 31, 2015 on July 31, 2012.

Additionally, under SB221, electric utilities and electric service companies are required to serve part of their load in 2011 from renewable energy resources equivalent to 1.00% of the average of the KWH they served in 2008-2010; in 2012 from renewable energy resources equivalent to 1.50% of the average of the KWH they served in 2009-2011; and in 2013 from renewable energy resources equivalent to 2.00% of the average of the KWH they served in 2010-2012. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RECs acquired through these two RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and beyond. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. The PUCO selected auditors to perform a financial and management audit, and final audit reports are currently scheduled to be filed with the PUCO on August 15, 2012. In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies have achieved their in-state solar compliance requirements for 2012.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire May 31, 2013, and provide for the competitive procurement of generation supply for customers that do not choose an alternative electric generation supplier or for customers of alternative electric generation suppliers 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 17, 2011, the Pennsylvania Companies filed a Joint Petition for Approval of their DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2013 through May 31, 2015. The ALJ issued a Recommended Decision on June 15, 2012, that supported adoption of the Pennsylvania Companies' proposed wholesale procurement plans, denial of their proposed Market Adjustment Charge, and various modifications to the proposed competitive enhancements. Exceptions to the Recommended Decision are currently pending. A final order must be entered by the PPUC by August 17, 2012.

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 began to refund those amounts to customers in January 2011, and the refunds are continuing over a 29 month period until the full amounts previously recovered for marginal transmission losses are refunded. In April 2010, ME and PN filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC's March 3, 2010 Order. On June 14, 2011, the Commonwealth Court issued an opinion and order affirming 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 and PN TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court and also a complaint seeking relief in the U.S. District Court for the Eastern District of Pennsylvania, which was subsequently amended. The PPUC filed a Motion to Dismiss ME and PN Amended Complaint on September 15, 2011 to which ME and PN responded and which remains pending. On February 28, 2012, the Supreme Court of Pennsylvania denied the Petition for Allowance of Appeal. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. The PPUC's brief in opposition is due on August 31, 2012, and the ME/PE reply is due on September 10, 2012. If the Supreme Court declines to take the case then ME and PE will pursue their claims in the proceedings that are pending in the U.S. District Court (E.D. PA).

In each of May 2008, 2009 and 2010, the PPUC approved ME's and PN's annual updates to their TSC rider for the annual periods between June 1, 2008 to December 31, 2010, including marginal transmission losses as approved by the PPUC, although the recovery of marginal transmission losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The PPUC's approval in May 2010 authorized an increase to the TSC for ME's customers to provide for full recovery by December 31, 2010. Although the ultimate outcome of this matter cannot be determined at this time, ME and PN believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million in marginal transmission losses for the period prior to January 1, 2011.

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 upon utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a final 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 has been unable to provide final results because several customers are still accumulating necessary documentation for projects that may qualify for inclusion in the final results. Preliminary numbers indicate that WP did not achieve its 2011 benchmark and it is not known at this time whether WP will be subject to a fine for failure to achieve the benchmark. WP is unable to predict the outcome of this matter or estimate any possible loss or range of loss.

On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes measures and a new program and implementation strategies consistent with the successful EE&C programs of ME, PN and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements. On January 6, 2012, a Joint Petition for Settlement of all issues was filed by the parties to the proceeding, and the ALJ's Recommended Decision was issued on April 19, 2012, recommending that the Joint Settlement be adopted as filed. The PPUC entered an order on May 10, 2012 approving the Joint Settlement.

In addition, Act 129 required utilities to file a SMIP with the PPUC. In light of the significant expenditures that would be associated with its smart meter deployment plans and related infrastructure upgrades, as well as its evaluation of recent PPUC decisions approving less-rapid deployment proposals by other utilities, WP re-evaluated its Act 129 compliance strategy, including both its plans with respect to its previously approved smart meter deployment plan and certain smart meter dependent aspects of the EE&C Plan. WP proposed to decelerate its previously contemplated smart meter deployment schedule and to target the installation of approximately 25,000 smart meters in support of its EE&C Plan, based on customer requests, by mid-2012. WP also proposed to take advantage of the 30-month grace period authorized by the PPUC to continue WP's efforts to re-evaluate full-scale smart meter deployment plans. WP would be permitted to recover certain previously incurred and anticipated smart-meter related expenditures through a levelized customer surcharge, with certain expenditures amortized over a ten-year period. A joint settlement with all parties based on these terms, with one party retaining the ability to challenge the recovery of amounts spent on WP's original smart meter implementation plan, was approved by the PPUC on June 30, 2011. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file by the end of 2012, or in a future base distribution rate case. The deadline for the Pennsylvania Companies to file their smart meter deployment plan is December 31, 2012.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market will 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. Following the issuance of a Tentative Order and comments filed by numerous parties, the PPUC entered a final order on December 16, 2011, providing recommendations for components to be included in upcoming DSPs, including: the duration of the programs and the length of associated energy contracts; a customer referral program; a retail opt-in auction; time-of-use rate options provided through contracts with electric generation suppliers; and periodic rate adjustments. Following the issuance of a Tentative Order and comments filed by various parties, the PPUC entered a final order on March 2, 2012 outlining an intermediate work plan. Several suggested models for long-range default service have been presented and were the topic of a March 2012 en banc hearing. It is expected that a tentative order will be issued for comment with a final long-range proposal.

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

WEST VIRGINIA

In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in a proceeding for an annual increase in retail rates 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 approved the Joint Petition and Agreement of Settlement in June 2010.

In January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities for purposes of compliance with their approved plan pursuant to AREPA. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the AREPA. Further, in February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP is entitled to all alternative and renewable energy resource credits associated with the electric energy, or energy and capacity, that MP is required to purchase pursuant to electric energy purchase agreements between MP and three NUG facilities in West Virginia. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, have participated in the case in opposition to the petition. The WVPSC issued an order granting ownership of all RECs produced by the facilities to MP. The West Virginia Supreme Court issued an Order on June 11, 2012, upholding the WVPSC's decision.

The City of New Martinsville and Morgantown Energy Associates have also filed complaints at FERC alleging the WVPSC order violated PURPA and requested FERC initiate an enforcement action. On April 24, 2012, the FERC ruled that the FERC-jurisdictional contracts are intended to pay only for electric energy and capacity (and not for RECs), and that state law controlled on the issues of determining which entity owns RECs and how they are transferred between entities. The FERC declined to act on the complaints and instead noted that the City of New Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. FERC also noted there may be language in the WVPSC decision that is inconsistent with PURPA. MP filed for rehearing of the FERC's order taking the position that the WVPSC order is consistent with PURPA. New Martinsville filed a complaint in the U.S. District Court on June 4, 2012, alleging that the WVPSC order violates PURPA.

On March 9, 2012, to assist the WVPSC with inquiries from public officials and the public, MP provided information to the WVPSC in the form of a closed entry filing in the ENEC case related to the plant deactivations. On April 2, 2012, the WVPSC issued an order requesting additional information from MP related to the Albright, Rivesville and Willow Island plant deactivation announcements. On April 30, 2012, MP provided the WVPSC with additional information regarding the plant deactivations. The WVPSC issued an order on July 13, 2012 finding the information provided to be sufficient and FirstEnergy's decision to deactivate the three plants reasonable. The WVPSC concluded FirstEnergy may proceed with its plan to deactivate the plants. MP anticipates deactivating these units by September 1, 2012.

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, FGCO, FENOC, ATSI and TrAIL. The 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. The financial impact of complying with future new or amended standards cannot be determined at this time; however, 2005 amendments to the FPA provide that all prudent costs incurred to comply with the future reliability standards be recovered in rates. Any future 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.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. On March 22, 2012, NERC concluded the investigation of the matter and forwarded it to NCEA for further review. NCEA is currently evaluating the findings of the investigation. JCP&L expects the matter to be resolved for an immaterial amount.

In 2011, RFC performed routine compliance audits of parts of FirstEnergy's bulk-power system and generally found the audited systems and processes to be in full compliance with all audited reliability standards. RFC will perform additional audits in 2012.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. The matter is contentious because costs for facilities built in one transmission zone often are allocated to customers in other transmission zones. During recent years, the debate has focused on the question of the methodology for determining the transmission zones and customers who benefit from a given facility and, if so, whether the methodology can determine the pro rata share of each zone's benefit. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" 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. This debate is framed by regulatory and court decisions. In 2007, 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 load serving entities in PJM bearing the majority of the costs. Subsequently, numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. 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 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.

Order No. 1000 issued by FERC on July 21, 2011, requires the submission of a compliance filing in October 2012 by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfies the principles set forth in the order. The PJM transmission owners have announced their intention to submit a compliance filing based on a hybrid methodology of 50% beneficiary pays and 50% postage stamp (or socialization) to be effective for projects approved by the PJM Board on and after the effective date of the compliance filing. FirstEnergy is working with other PJM transmission owners to develop the required filing based on this proposed methodology.

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 most of the matters involved with the move have been resolved, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed; the details of which dispute are discussed below in the "MISO Multi-Value Project Rule Proposal." In addition, FERC denied certain exit fees of ATSI's transmission rate until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. ATSI has asked for rehearing of FERC's orders that address the Michigan Thumb transmission project, and the exit fee issue.

ATSI's filings and requests for rehearing on these matters, as well as the pleadings submitted by parties that oppose ATSI's position are currently pending before FERC. Finally, a negotiated agreement that requires ATSI to pay a one-time charge of $1.8 million for long term firm transmission rights that, according to the MISO, were payable upon ATSI's exit, is pending before FERC.

The final outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners (not including ATSI or FirstEnergy) jointly filed with FERC a proposed cost allocation methodology for certain new transmission projects. The new transmission projects - described as MVPs - are a class of transmission projects that are approved via MISO's MTEP process. Under MISO's proposal, the costs of “Michigan Thumb” MVP projects that were approved by MISO's Board prior to the June 1, 2011 effective date of FirstEnergy's integration into PJM would continue to be allocated to and charged to ATSI. MISO estimated that approximately $15 million in annual revenue requirements associated with the Michigan Thumb Project would be allocated to the ATSI zone upon completion of project construction.

FirstEnergy has filed pleadings in opposition to the MISO's efforts to “socialize” the costs of the Michigan Thumb Project onto ATSI or onto ATSI's customers that assert legal, factual and policy arguments. To date, FERC has responded in a series of orders that require ATSI to absorb the charges for the Michigan Thumb Project.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of the FERC's orders with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November 2011, the cases were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit with briefs due from the parties through 2012 and oral argument to be scheduled in 2013.

In February 2012, FERC issued its most recent order (February 2012 Order) regarding the Michigan Thumb Project, in which FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. MISO's Schedule 39 tariff is the vehicle through which the MISO plans to charge the Michigan Thumb project costs to ATSI. FERC also set for hearing the question of whether it is just and reasonable for ATSI to pay the Michigan Thumb project costs and, if so, the amount of and methodology for calculating ATSI's Michigan Thumb project cost responsibility. On March 28, 2012, FirstEnergy filed for clarification and rehearing of the February 2012 Order, and such request is pending before the FERC. On July 10, 2012, a prehearing conference was convened before a FERC ALJ who will determine the scope of the hearing and thereafter set the hearing schedule.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

PJM Underfunding FTR Complaint

On December 28, 2011, FES and AE Supply filed a complaint with FERC against PJM challenging the ongoing underfunding of FTR contracts, which exist to hedge against transmission congestion in the day-ahead markets. The underfunding is a result of PJM's practice of using the funds that are intended to pay the holders of FTR contracts to pay instead for congestion costs that occur in the real time markets. Underfunding of the FTR contracts resulted in losses of approximately $35 million ($0.5 million - FES; $34.5 million - AE Supply) in the 2010-2011 Delivery Year. Losses for the 2011-2012 Delivery Year are estimated to be approximately $11.5 million ($11.4 million - FES; $0.1 million - AE Supply).

On January 13, 2012, PJM filed comments describing changes to the PJM tariff that, if adopted, should remedy the underfunding issue. On March 2, 2012, FERC dismissed the complaint without prejudice, pending PJM's publication for stakeholder review and discussion, a report on the causes of the FTR underfunding and potential improvements, including modeling, which could be made to minimize the revenue inadequacy. On March 30, 2012, FES and AE Supply requested rehearing and reconsideration of the March 2, 2012 order. On July 19, 2012, FERC issued its Order on Rehearing and again dismissed FirstEnergy's complaint without prejudice. FERC noted PJM's ongoing stakeholder process and directed that if the issues were not addressed in that process FirstEnergy could file its complaint again.

FTR Allocation Complaint

On March 26, 2012, FES and AE Supply filed a complaint with FERC against PJM challenging PJM's FTR allocation rules. PJM allocates FTRs to load-serving entities in an annual allocation process, up to each LSE's peak load, based on the expected transmission capability for the upcoming planning year. If a transmission facility is scheduled to be out of service for a significant part of the year, it can result in LSEs' FTR allocations being reduced in the annual allocation. When these transmission facilities return to service during the year, PJM will create monthly FTRs to reflect the increased transmission capability during that month. However, instead of allocating these new monthly FTRs to the LSEs that were unable to obtain their full allocation of FTRs in the annual allocation process, PJM's rules instead require PJM to auction off these new monthly FTRs in the market. The complaint seeks a change to the PJM rules such that the new FTRs created each month by transmission lines returning to service would first be allocated to those LSEs that were denied a full allocation of their FTR entitlement in the annual allocation process before they are auctioned off in the market. On April 16, 2012, PJM filed its answer to the complaint. Exelon Corporation filed a protest, and several other parties filed comments. On July 11, 2012, FERC issued its Order Granting Complaint and Requiring a Compliance Filing. In the order, FERC agreed with FirstEnergy's description of the issues and with FirstEnergy's proposed changes to PJM's rules, and FERC directed PJM to submit a compliance filing within 60 days to implement the changes in the rules.

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 United States Court of Appeals for the Ninth Circuit in 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 has since remanded one of those proceedings to FERC, which arises out of claims previously filed with FERC by the California Attorney General on behalf of certain California parties against various sellers in the California wholesale power market, including AE Supply (the Lockyer case). In March 2010, the judge assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. On May 4, 2011, FERC affirmed the judge's ruling. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. By Order issued June 13, 2012, FERC denied the request for rehearing. On June 21, 2012, the California Parties appealed the FERC's decision to the Ninth Circuit Court of Appeals.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second complaint with FERC against various sellers, including AE Supply (the Brown case), again seeking refunds for trades in the California energy markets during 2000 and 2001. The above-noted trades with CDWR are the basis for including AE Supply in this additional complaint. AE Supply filed a motion to dismiss the Brown complaint that was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. By Order issued June 13, 2012, that request for rehearing also was denied. On June 21, 2012, the California Parties appealed the FERC's decision to the Ninth Circuit Court of Appeals. 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 is comprised of a 765 kV transmission line that was proposed to extend 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. In December 2010, PJM advised that its 2011 Load Forecast Report included load projections that are different from previous forecasts and that may have an impact on the proposed in-service date for the PATH Project. As part of its 2011 RTEP, and in response to a January 19, 2011, directive by a Virginia Hearing Examiner, PJM conducted a series of analyses using the most current economic forecasts and demand response commitments, as well as potential new generation resources. Preliminary analysis revealed the expected reliability violations that necessitated the PATH Project had moved several years into the future. Based on those results, PJM announced on February 28, 2011, that its Board of Managers had decided to hold the PATH Project in abeyance in its 2011 RTEP and directed FirstEnergy and AEP, as the sponsoring transmission owners, to suspend current development efforts on the project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the need for the project as part of its continuing RTEP process. PJM stated that its action did not constitute a directive to FirstEnergy and AEP to cancel or abandon the PATH Project. PJM further stated that it will complete a more rigorous analysis of the PATH Project and other transmission requirements and its Board will review this comprehensive analysis as part of its consideration of the 2011 RTEP. The PJM Board has directed the PJM staff to perform additional analysis using the 2012 RTEP assumptions and incorporating the results of the May 2012 RPM base residual auction. The PJM staff is expected to report its conclusions from this analysis to the Transmission Expansion Advisory Committee on August 9, 2012. All applications for authorization to construct the project filed with state commissions have been withdrawn.

Yards Creek

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC, a subsidiary of Public Service Enterprise Group, owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. FERC issued a license for authorization to operate the project. The existing license expires on February 28, 2013.

In February 2011, JCP&L and PSEG filed a joint application with FERC to renew the license for an additional forty years. The companies are pursuing relicensure through FERC's ILP. Under the ILP, FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the five-year ILP licensure process. FirstEnergy expects FERC to issue the new license before February 28, 2013. To the extent, however, that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended yearly as necessary to permit FERC to issue the new license.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FGCO. FGCO holds the current FERC license that authorizes ownership and operation of the project. The current FERC license will expire on November 30, 2015. FERC's regulations call for a five-year relicensing process. On November 24, 2010, and acting pursuant to applicable FERC regulations and rules, FGCO initiated the relicensing process by filing its notice of intent to relicense and related documents in the license docket.

On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and related documents necessary for the Seneca Nation to submit a competing application. Section 15 of the FPA contemplates that third parties may file a "competing application" to assume ownership and operation of a hydroelectric facility upon (i) relicensure and (ii) payment of net book value of the plant to the original owner/operator. Nonetheless, FGCO believes it is entitled to a statutory “incumbent preference” under Section 15.

The Seneca Nation and certain other intervenors have asked FERC to redefine the “project boundary” of the hydroelectric plant to include the dam and reservoir facilities operated by the U.S. Army Corps of Engineers. On May 16, 2011, FirstEnergy filed a Petition for Declaratory Order with FERC seeking an order to exclude the dam and reservoir facilities from the project. The Seneca Nation, the New York State Department of Environmental Conservation, and the U.S. Department of Interior each submitted responses to FirstEnergy's petition, including motions to dismiss FirstEnergy's petition. The “project boundary” issue is pending before FERC.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On October 11, 2011, FERC Staff issued a letter order that addressed the Revised Study Plans. In the order, FERC Staff approved FirstEnergy's Revised Study Plan, subject to a finding that the Project is located on “aboriginal lands” of the Seneca Nation. Based on this finding, FERC Staff directed FirstEnergy to consult with the Seneca Nation and other parties about the data set, methodology and modeling of the hydrological impacts of project operations. In March of 2012, FirstEnergy hosted a meeting as part of the consultation process. In that meeting, FirstEnergy reviewed its proposed methodology for conducting the hydrological impacts study and answered questions from third parties about the methodology. On April 11, 2012, the Seneca Nation and other parties filed comments on the proposed hydrologic impacts study. The study processes, including the discrete hydrological impacts study, will extend through approximately November 2013.

FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

MISO Capacity Portability

On June 11, 2012, the 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. FERC is responding to suggestions from MISO Stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. Comments are due on August 10, 2012, and reply comments are due on August 27, 2012. 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 the prices at which those auctions would clear. FirstEnergy anticipates submitting initial comments by August 10, 2012 and, depending on the comments submitted by other parties, submitting reply comments by August 27, 2012.

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, 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 FGCO 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. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

In December 2007, the states of New Jersey and Connecticut filed CAA citizen suits in the U.S. District Court for the Eastern District of Pennsylvania alleging NSR violations at the coal-fired Portland Generation Station against GenOn Energy, Inc. (formerly RRI Energy, Inc. and the current owner and operator), Sithe Energy (the purchaser of the Portland Station from ME in 1999) and ME. Specifically, these suits allege that “modifications” at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR permitting in violation of the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. The Court dismissed New Jersey's and Connecticut's claims for injunctive relief against ME, but denied ME's motion to dismiss the claims for civil penalties. The parties dispute the scope of ME's indemnity obligation to and from Sithe Energy. In February 2012, GenOn announced its plans to retire the Portland Station in January 2015 citing EPA emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. On July 27, 2012, FirstEnergy filed a motion for summary judgment arguing the Plaintiff's remaining claims for civil penalties are barred by the statute of limitations. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued a NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on “modifications” dating back to 1984. ME, JCP&L and PN, as former owners of the facilities, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant between 1991 to 1994 without preconstruction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and have filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals. PN believes the claims are without merit and intends to 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 loss or possible range of loss. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International.

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. FGCO 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 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 a 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, EPA issued another CAA section 114 request 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 vigorously defend against these CAA matters, but cannot predict their outcomes 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 Allegheny performed major modifications in violation of the PSD 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. The parties are awaiting a decision from the District Court, but there is no deadline for that decision. FirstEnergy is unable to predict the outcome or estimate the possible loss or range of loss.

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 District of Columbia 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 June 12, 2012, the EPA revised certain CSAPR state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas), certain generating unit allocations (for some units in Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and delayed from 2012 to 2014 certain allowance penalties that could apply with respect to interstate trading of NOx and SO_2 emission allowances. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit pending a decision on legal challenges argued before the Court on April 13, 2012. The Court ordered EPA to continue administration of CAIR until the Court resolves the CSAPR appeals. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's 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. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On January 26, 2012 and February 8, 2012, FGCO, MP and AE Supply announced the deactivation by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lake Shore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW (generating, on average, approximately ten percent of the electricity produced by the companies over the past three years) due to MATS and other environmental regulations. MATS has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. FirstEnergy and other entities have also petitioned EPA to reconsider and revise various regulatory requirements under MATS. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS is estimated to be $975 million and other changes to FirstEnergy's operations may result.

On March 8, 2012, FGCO filed an application for a feasibility study with PJM to install and interconnect to the transmission system 832 megawatts of new combustion turbine peaking generation at its existing Eastlake Plant in Eastlake, Ohio, to help ensure reliable electric service in the region. However, when these units did not clear the May PJM capacity auction, the decision was made to not proceed with the project at this time. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from our previously announced plant deactivations and requested RMR arrangements for Eastlake 1-3, Ashtabula 5 and Lake Shore 18. On July 10, 2012, FirstEnergy filed with FERC, for informational purposes, the compensation arrangements for these units which will remain in effect for as long as these generating units continue to operate. On July 16, 2012, FGCO and ATSI filed an application with FERC for authorization to transfer from FGCO to ATSI certain assets associated with Eastlake Units 1-5 and Lakeshore Unit 18 for conversion to synchronous condensers by ATSI for transmission reliability purposes as directed by PJM. Upon FERC approval, it is expected that the assets will be transferred in staggered closings when the units are no longer needed for RMR purposes. During the three months and six months ended June 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $10 million ($6 million by FES) and $17 million ($10 million by FES), respectively, as a result of the deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

On March 9, 2012, to assist the WVPSC with inquiries from public officials and the public, MP provided information to the WVPSC in the form of a closed entry filing in the ENEC case related to the plant deactivations. On April 2, 2012, the WVPSC issued an order requesting additional information from MP related to the Albright, Rivesville and Willow Island plant deactivation announcements. On April 30, 2012, MP provided the WVPSC with additional information regarding the plant deactivations. The WVPSC issued an order on July 13, 2012 finding the information provided to be sufficient and FirstEnergy's decision to deactivate the three plants reasonable. The WVPSC concluded FirstEnergy may proceed with its plan to deactivate the plants. MP anticipates deactivating these units by September 1, 2012.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security

Act of 2009, in June 2009. Certain states, primarily the northeastern states participating in the RGGI and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required FirstEnergy to measure and report 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 preconstruction 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.

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. 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 from 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. A December 2011 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.

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. In July 2012, the period for finalizing the Section 316(b) regulation was extended to July 27, 2013. 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 water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking 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.

In April 2011, the U.S. Attorney's Office in Cleveland, Ohio advised FGCO that it is no longer considering prosecution under the CWA and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. On June 5, 2012, FirstEnergy executed a tolling agreement with the EPA extending the statute of limitations for civil liability claims for those petroleum spills to January 31, 2013. FGCO does not anticipate any losses resulting from this matter to be material.

In late 2008, the PA DEP imposed water quality criteria for certain effluents, including TDS and sulfate concentrations in the Monongahela River, on new and modified sources, including the scrubber project at the coal-fired Hatfield's Ferry Plant. These criteria are reflected in the NPDES water discharge permit issued by PA DEP for that project. In January 2009, AE Supply appealed the PA DEP's permitting decision to the EHB, due to estimated costs in excess of $150 million in order to install technology to meet TDS and sulfate limits in the NPDES permit. Environmental Integrity Project and Citizens Coal Council also appealed the NPDES permit seeking to impose more stringent technology-based effluent limitations. In April 2012, a joint motion was filed by the parties informing the EHB of a proposed settlement and seeking the lifting of a portion of the EHB's stay of certain terms of the Hatfield's Ferry Plant's NPDES permit. The joint motion was granted by the EHB on April 27, 2012. The proposed settlement, in the form of a Consent Decree, was lodged with the Commonwealth Court of Pennsylvania and published in the June 23, 2012, Pennsylvania Bulletin for a 30-day public comment period. The Consent Decree, if entered by the Commonwealth Court of Pennsylvania, will resolve the disputes concerning the Hatfield's Ferry Plant NPDES permit, including TDS and sulphate limits.

The PA DEP recommended, and in August 2010, the Pennsylvania Environmental Quality Board issued, a final rule imposing end-of-pipe TDS effluent limitations. FirstEnergy could incur significant costs for additional control equipment to meet the requirements of this rule, although its provisions do not apply to electric generating units until the end of 2018, and then would apply only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

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. PA DEP's goal is to submit a final water quality standards regulation, incorporating the sulfate impairment designation for EPA approval by May 2013. PA DEP will then need to develop a TMDL limit for the river, a process that will take approximately five years. Based on the stringency of the TMDL, FirstEnergy may incur significant costs to reduce sulfate discharges into the Monongahela River from the coal-fired Hatfield's Ferry and Mitchell Plants in Pennsylvania and the coal-fired Fort Martin Plant in West Virginia.

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 has 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 in excess of the capital investment that may be needed at Hatfield's Ferry 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 May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit in the U.S. District Court for the Northern District of West Virginia alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash impoundments at the Albright Station seeking unspecified civil penalties and injunctive relief. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served a 60-day Notice of Intent required prior to filing a citizen suit under the CWA for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Plant. MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. On January 3, 2012, the Court denied MP's motion to dismiss or stay the CWA citizen suit but without prejudice to re-filing in the future. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. If approved by the Court, a Consent Decree will be entered by the Court to resolve these claims. MP is currently seeking relief from the arsenic limits through WVDEP agency review.

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 Resource Conservation and Recovery Act 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 coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, 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 coal combustion residuals. On July 27, 2012, the PA DEP filed a complaint against FGCO in the U.S. District Court for the Western District of Pennsylvania with claims under the Resource Conservation and Recovery Act and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FGCO to resolve those claims. The Consent Decree will be published to allow for a 30-day public comment period and requires FGCO 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 Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. BMP is pursuing several options for disposal of

CCB following December 31, 2016.

FirstEnergy's future cost of compliance with any coal combustion residuals 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 our 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, 2012, 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 $122 million (including $86 million applicable to JCP&L) have been accrued through June 30, 2012. Included in the total are accrued liabilities of approximately $79 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, 2012, FirstEnergy had approximately $2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. 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. FirstEnergy Corp. currently maintains a $95 million parental guaranty in support of the decommissioning of nuclear facilities.

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. By an order dated April 26, 2011, a NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. The NRC subsequently narrowed the scope of admitted contentions in this proceeding to a challenge to the computer code used to model source terms in FENOC's Severe Accident Mitigation Alternatives analysis. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the cracking of the Davis-Besse shield building discussed below. The intervenors supplemented their petition for a contention on the shield building on multiple occasions. On July 9, 2012, the intervenors petitioned the ASLB for a new contention on the environmental impacts of temporary spent fuel storage at Davis-Besse due to the lack of a repository and the disposal of these wastes. The ASLB has yet to rule on the admission of these latest requests for new contentions.

Similarly, on June 18 and 19, 2012, the intervenors in the Davis-Besse license renewal proceeding and other petitioners requested that the NRC suspends the issuance of final decisions in all pending reactor licensing proceedings as a result of the decision in the case of State of New York v. NRC, No. 11-1045. (D.C. Cir. June 8, 2012). In this case, the D.C. Circuit vacated the NRC's updated Waste Confidence Decision and its Temporary Storage Rule and remanded those rulemakings to the NRC for further consideration. FENOC and other Licensees opposed the suspension request. By order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the D.C. Circuit decision and all pending contentions on this topic should be held in abeyance until further order. The NRC also directed that all licensing reviews and proceedings should continue to move forward.

On October 1, 2011, Davis-Besse was safely shut down for a scheduled outage to install a new reactor vessel head and complete other maintenance activities. The new reactor head, which replaced a head installed in 2002, enhances safety and reliability, and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, following opening of the building for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above elevation 780') and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers has determined these conditions do not affect the facility's structural integrity or safety.

On December 2, 2011, the NRC issued a CAL which concluded that FENOC provided "reasonable assurance that the shield building remains capable of performing its safety functions." The CAL imposed a number of commitments from FENOC, including, submitting a root cause evaluation and corrective actions to the NRC by February 28, 2012, and further evaluations of the shield building. On February 27, 2012, FENOC sent the root cause evaluation to the NRC. Finally, the CAL also stated that the NRC was still evaluating whether the current condition of the shield building conforms to the plant's licensing basis. On December 6, 2011, the Davis-Besse plant returned to service. On June 21, 2012, the NRC issued an Inspection Report that concluded that FENOC established a sufficient basis for the causes of the shield building laminar cracking.

By letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff will conduct several supplemental inspections, culminating in an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues are understood, the extent of condition has been identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. Additional adverse findings by the NRC could result in further inspection activities.

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.

On February 16, 2012, the NRC issued a request for information to the licensed operators of 11 nuclear power plants, including Beaver Valley Power Station Units 1 and 2, with respect to the modeling of fuel performance as it relates to "thermal conductivity degradation," which is the potential in higher burn up fuel for reduced capacity to transfer heat that could potentially change its performance during various accident scenarios, including loss of coolant accidents. The request for information indicated that this phenomenon has not been accounted for adequately in performance models for the fuel developed by the fuel manufacturer and that the NRC might consider imposing restrictions on reactor operating limits. On March 16, 2012, FENOC submitted its response to the NRC demonstrating that the NRC requirements are being met. FENOC also agreed to submit to the NRC revised large break loss of coolant accident analyses by December 15, 2016, that further consider the effects of fuel pellet thermal conductivity degradation.

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 Coal Sales Agreement 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, which issue can be the subject of a future appeal. 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 have 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 claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to 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 replacement coal / 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, ICG posted bond and filed a Notice of Appeal. Briefing on the Appeal has concluded and an oral argument was held on May 16, 2012. A decision from the Appellate court is expected in the fourth quarter of 2012. AE Supply and MP intend to vigorously pursue this matter through appeal.

Other Legal Matters

In February 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount had been approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction. The court granted the motion to dismiss and the plaintif