FORM 10-Q

Quarterly report pursuant to sections 13 or 15(d)

Filing Date: **2012-12-11** | Period of Report: **2012-09-30**
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FILER

JERSEY CENTRAL POWER & LIGHT CO

CIK:**53456**| IRS No.: **210485010** | State of Incorp.:**NJ** | Fiscal Year End: **1231**
Type: **10-Q** | Act: **34** | File No.: **001-03141** | Film No.: **121254615**
SIC: **4911** Electric services

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C/O FIRSTENERGY CORP.
AKRON OH 44308-1890

Business Address
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C/O FIRSTENERGY CORP.
AKRON OH 44308-1890
330-761-7837

OHIO EDISON CO

CIK:**73960**| IRS No.: **340437786** | State of Incorp.:**OH** | Fiscal Year End: **1231**
Type: **10-Q** | Act: **34** | File No.: **001-02578** | Film No.: **121254614**
SIC: **4911** Electric services

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FirstEnergy Solutions Corp.

CIK:**1407703**| IRS No.: **311560186** | State of Incorp.:**OH** | Fiscal Year End: **1231**
Type: **10-Q** | Act: **34** | File No.: **000-53742** | Film No.: **121254613**
SIC: **4911** Electric services

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800-736-3402

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 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 ☑ No ☐ 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 ☑ No ☐ 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 ☑	FirstEnergy Corp.
Accelerated Filer ☐	N/A
Non-accelerated Filer (Do not check if a smaller reporting company) ☑	FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company
Smaller Reporting Company ☐	N/A

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

Yes ☐ No ☑ 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 NOVEMBER 7, 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.

EXPLANATORY NOTE

The attached combined Form 10-Q was filed on November 8, 2012 in its entirety, but such filing was made under the central index code ("CIK") for the parent company, FirstEnergy Corp., only. We are hereby refiling the combined Form 10-Q under the CIK codes for the following subsidiary registrants: FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company.

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 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.
- Changing energy, capacity 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 CAIR, and any laws, rules or regulations that ultimately replace CAIR, 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 deactivate or idle certain generating units).
- The uncertainties associated with our plans to deactivate our older unscrubbed regulated and competitive fossil units and our plans to change the operations of certain fossil plants, including the impact on vendor commitments, and the timing of those deactivations and operational changes 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 Regulated Distribution and Competitive Energy Services segments.
- 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 Pinesdale LLC that owns Global Rail and Signal Peak
Global Rail	A subsidiary of Global Holdings 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
PATH-WV	PATH West Virginia 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	An indirect subsidiary of Global Holdings 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.
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board

BGS	Basic Generation Service

GLOSSARY OF TERMS, *Continued*

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
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
EIS	Environmental Impact Statement
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
LOC	Letter of Credit
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatt

GLOSSARY OF TERMS, *Continued*

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	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMI	Retail Markets Investigation
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SAMA	Severe Accident Mitigation Alternatives
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
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load

GLOSSARY OF TERMS, *Continued*

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)

(In millions, except per share amounts)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
REVENUES:				
Electric utilities	$ 2,624	$ 3,041	$ 7,414	$ 7,966
Unregulated businesses	1,687	1,678	4,844	4,389
Total revenues*	4,311	4,719	12,258	12,355
OPERATING EXPENSES:				
Fuel	636	632	1,833	1,720
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
Amortization of regulatory assets, net	61	122	198	344
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Investment income	39	48	63	100
Interest expense	(230)	(267)	(750)	(763)
Capitalized interest	18	17	54	55
Total other expense	(173)	(202)	(633)	(608)
INCOME BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES	309	325	658	550
NET INCOME	425	530	919	770
Income (loss) attributable to noncontrolling interest	—	(2)	1	(17)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 425	$ 532	$ 918	$ 787
EARNINGS PER SHARE OF COMMON STOCK:				
Basic	$ 1.02	$ 1.27	$ 2.20	$ 2.01
Diluted	$ 1.01	$ 1.27	$ 2.19	$ 2.00
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	417	418	418	392
Diluted	419	420	419	394

DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$	1.10	$	1.10	$	1.65	$	1.65

* Includes excise tax collections of $123 million and $137 million in the three months ended September 30, 2012 and 2011, respectively, and $351 million and $371 million in the nine months ended September 30, 2012 and 2011, respectively.

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
NET INCOME	$ 425	$ 530	$ 919	$ 770
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(47)	(48)	(148)	(44)
Amortized losses on derivative hedges	—	2	1	13
Change in unrealized gain on available-for-sale securities	1	(26)	13	(7)
Other comprehensive loss	(46)	(72)	(134)	(38)
Income tax benefits on other comprehensive loss	(24)	(26)	(75)	(12)
Other comprehensive loss, net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
Comprehensive income (loss) attributable to noncontrolling interest	—	(2)	1	(17)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 403	$ 486	$ 859	$ 761

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)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 150	$ 202
Receivables-		
Customers, net of allowance for uncollectible accounts of $43 in 2012 and $37 in 2011	1,604	1,525
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	227	269
Materials and supplies	875	811
Prepaid taxes	227	191
Derivatives	212	235
Accumulated deferred income taxes	224	—
Other	190	122
	3,709	3,355
PROPERTY, PLANT AND EQUIPMENT:		
In service	41,756	40,122
Less — Accumulated provision for depreciation	12,434	11,839
	29,322	28,283
Construction work in progress	2,119	2,054
	31,441	30,337
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,203	2,112
Investments in lease obligation bonds	210	402
Other	1,038	1,008
	3,451	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,444	6,441
Regulatory assets	2,113	2,030
Other	1,580	1,641
	10,137	10,112
	$ 48,738	$ 47,326
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,473	$ 1,621
Short-term borrowings	1,604	—
Accounts payable	925	1,174
Accrued taxes	508	558
Accrued compensation and benefits	313	384
Derivatives	155	218
Other	942	900
	5,920	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	9,758	9,765
Accumulated other comprehensive income	367	426
Retained earnings	3,266	3,047
Total common stockholders' equity	13,433	13,280
Noncontrolling interest	16	19
Total equity	13,449	13,299
Long-term debt and other long-term obligations	15,627	15,716
	29,076	29,015
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,543	5,670
Retirement benefits	2,271	2,823
Asset retirement obligations	1,574	1,497
Deferred gain on sale and leaseback transaction	900	925
Adverse power contract liability	550	469
Other	1,904	2,072
	13,742	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$ 48,738	$ 47,326

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 919	$ 770
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	859	809
Amortization of regulatory assets, net	198	344
Nuclear fuel and lease amortization	163	152
Deferred purchased power and other costs	(214)	(222)
Deferred income taxes and investment tax credits, net	712	696
Deferred rents and lease market valuation liability	(62)	(17)
Accrued compensation and retirement benefits	(168)	(25)
Commodity derivative transactions, net	(80)	(22)
Pension trust contributions	(600)	(375)
Asset impairments	10	59
Cash collateral, net	(3)	(66)
Decrease (increase) in operating assets-		
Receivables	(41)	139
Materials and supplies	(63)	62
Prepayments and other current assets	(151)	(1)
Increase (decrease) in operating liabilities-		
Accounts payable	(250)	(154)
Accrued taxes	(50)	20
Accrued interest	50	67
Other	47	(7)
Net cash provided from operating activities	1,276	2,229
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	660	603
Short-term borrowings, net	1,604	—
Redemptions and Repayments-		
Long-term debt	(870)	(1,581)
Short-term borrowings, net	—	(700)
Common stock dividend payments	(690)	(651)
Other	(42)	(73)
Net cash provided from (used for) financing activities	662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,686)	(1,464)
Nuclear fuel	(207)	(65)

Proceeds from asset sales	17	519
Sales of investment securities held in trusts	2,133	3,678
Purchases of investment securities held in trusts	(2,188)	(3,801)
Cash investments	100	51
Cash received in AE merger	—	590
Cost of removal	(119)	(57)
Other	(40)	(6)
Net cash used for investing activities	(1,990)	(555)
Net change in cash and cash equivalents	(52)	(728)
Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	$ 150	$ 291
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction: merger with AE, common stock issued	$ —	$ 4,354

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

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales to non-affiliates	$ 1,339	$ 1,251	$ 3,964	$ 3,348
Electric sales to affiliates	155	143	385	574
Other	63	73	180	229
Total revenues	1,557	1,467	4,529	4,151
OPERATING EXPENSES:				
Fuel	303	386	978	1,045
Purchased power from affiliates	131	55	381	189
Purchased power from non-affiliates	499	328	1,420	954
Other operating expenses	343	390	1,031	1,268
Provision for depreciation	71	69	203	207
General taxes	35	31	104	91
Impairment of long-lived assets	—	2	—	22
Total operating expenses	1,382	1,261	4,117	3,776
OPERATING INCOME	175	206	412	375
OTHER INCOME (EXPENSE):				
Investment income	38	28	50	50
Miscellaneous income	1	9	25	17
Interest expense — affiliates	(3)	(2)	(7)	(5)
Interest expense — other	(51)	(51)	(140)	(156)
Capitalized interest	9	8	27	28
Total other expense	(6)	(8)	(45)	(66)
INCOME BEFORE INCOME TAXES	169	198	367	309
INCOME TAXES	68	78	145	115
NET INCOME	$ 101	$ 120	$ 222	$ 194
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 101	$ 120	$ 222	$ 194
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(5)	(5)	(2)	(14)
Amortized gain (loss) on derivative hedges	(2)	(1)	(6)	4

Change in unrealized gain on available-for-sale securities	(2)	(22)	11	(7)
Other comprehensive income (loss)	(9)	(28)	3	(17)
Income taxes (benefits) on other comprehensive income (loss)	(3)	(11)	1	(7)
Other comprehensive income (loss), net of tax	(6)	(17)	2	(10)
COMPREHENSIVE INCOME	$ 95	$ 103	$ 224	$ 184

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

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3	$ 7
Receivables-		
Customers, net of allowance for uncollectible accounts of $16 in 2012 and 2011	485	424
Affiliated companies	402	600
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	103	61
Notes receivable from affiliated companies	438	383
Materials and supplies	533	492
Derivatives	209	219
Prepayments and other	137	38
	2,310	2,224
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,638	10,983
Less — Accumulated provision for depreciation	4,312	4,110
	7,326	6,873
Construction work in progress	1,055	1,014
	8,381	7,887
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,286	1,223
Other	16	7
	1,302	1,230
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	114	123
Goodwill	24	24
Property taxes	43	43
Unamortized sale and leaseback costs	111	80
Derivatives	78	79
Other	181	129
	551	478
	$ 12,544	$ 11,819
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,074	$ 905
Accounts payable-		
Affiliated companies	787	436
Other	174	220
Accrued taxes	83	227
Derivatives	153	189
Other	244	261

	2,515	2,238
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,571	1,570
Accumulated other comprehensive income	78	76
Retained earnings	2,153	1,931
Total common stockholder's equity	3,802	3,577
Long-term debt and other long-term obligations	3,085	2,799
	6,887	6,376
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	900	925
Accumulated deferred income taxes	501	286
Asset retirement obligations	950	904
Retirement benefits	183	356
Lease market valuation liability	87	171
Other	521	563
	3,142	3,205
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$ 12,544	$ 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)	Nine Months Ended September 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 222	$ 194
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	203	207
Nuclear fuel and lease amortization	159	151
Deferred rents and lease market valuation liability	(144)	(37)
Deferred income taxes and investment tax credits, net	123	246
Asset impairments	8	40
Accrued compensation and retirement benefits	11	(31)
Pension trust contribution	(209)	—
Commodity derivative transactions, net	(67)	(54)
Cash collateral, net	(4)	(81)
Decrease (increase) in operating assets-		
Receivables	95	(34)
Materials and supplies	(40)	72
Prepayments and other current assets	5	8
Increase (decrease) in operating liabilities-		
Accounts payable	292	(113)
Accrued taxes	(144)	24
Other	(9)	(55)
Net cash provided from operating activities	501	537
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	560	247
Short-term borrowings, net	3	—
Redemptions and repayments-		
Long-term debt	(246)	(791)
Short-term borrowings, net	—	(12)
Other	(9)	(10)
Net cash provided from (used for) financing activities	308	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(535)	(408)
Nuclear fuel	(207)	(65)
Proceeds from asset sales	17	519
Sales of investment securities held in trusts	1,167	1,613
Purchases of investment securities held in trusts	(1,194)	(1,654)

Loans to affiliated companies, net	(55)	57
Other	(6)	(36)
Net cash provided from (used for) investing activities	(813)	26
Net change in cash and cash equivalents	(4)	(3)
Cash and cash equivalents at beginning of period	7	9
Cash and cash equivalents at end of period	$ 3	$ 6

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

OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 426	$ 441	$ 1,149	$ 1,165
Excise and gross receipts tax collections	28	29	79	82
Total revenues	454	470	1,228	1,247
OPERATING EXPENSES:				
Purchased power from affiliates	38	57	128	220
Purchased power from non-affiliates	79	80	215	203
Other operating expenses	124	114	364	316
Provision for depreciation	26	23	75	69
Amortization of regulatory assets, net	42	46	57	49
General taxes	52	51	148	146
Total operating expenses	361	371	987	1,003
OPERATING INCOME	93	99	241	244
OTHER INCOME (EXPENSE):				
Investment income	8	11	17	20
Interest expense	(23)	(22)	(68)	(66)
Capitalized interest	—	—	2	1
Total other expense	(15)	(11)	(49)	(45)
INCOME BEFORE INCOME TAXES	78	88	192	199
INCOME TAXES	34	34	76	72
NET INCOME	$ 44	$ 54	$ 116	$ 127
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 44	$ 54	$ 116	$ 127
OTHER COMPREHENSIVE LOSS:				
Pensions and OPEB prior service costs	(7)	(6)	(24)	(21)
Change in unrealized gain on available-for-sale securities	—	(3)	—	(1)
Other comprehensive loss	(7)	(9)	(24)	(22)
Income tax benefits on other comprehensive loss	(4)	(4)	(13)	(11)
Other comprehensive loss, net of tax	(3)	(5)	(11)	(11)

COMPREHENSIVE INCOME	$ 41	$ 49	$ 105	$ 116

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)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 50	$ 26
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2012 and 2011	179	163
Affiliated companies	52	86
Other	20	41
Notes receivable from affiliated companies	258	181
Prepayments and other	9	17
	568	514
UTILITY PLANT:		
In service	3,490	3,358
Less — Accumulated provision for depreciation	1,308	1,267
	2,182	2,091
Construction work in progress	96	91
	2,278	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	293	363
Property taxes	81	81
Unamortized sale and leaseback costs	21	25
Other	27	19
	422	488
	$ 3,648	$ 3,574
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 3	$ 2
Accounts payable-		
Affiliated companies	81	119
Other	30	35
Accrued taxes	94	88
Accrued interest	25	25
Other	111	79
	344	348
CAPITALIZATION:		
Common stockholder's equity-		

Common stock, without par value, authorized 175,000,000 shares – 60 shares outstanding	698	747
Accumulated other comprehensive income	43	54
Retained earnings (accumulated deficit)	32	(84)
Total common stockholder's equity	773	717
Noncontrolling interest	5	5
Total equity	778	722
Long-term debt and other long-term obligations	1,157	1,155
	1,935	1,877
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	812	787
Retirement benefits	208	213
Asset retirement obligations	75	71
Other	274	278
	1,369	1,349
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 3,648	$ 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)

(In millions)	Nine Months Ended September 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 116	$ 127
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	75	69
Amortization of regulatory assets, net	57	49
Amortization of lease costs	28	28
Deferred income taxes and investment tax credits, net	41	72
Accrued compensation and retirement benefits	(35)	(25)
Pension trust contribution	—	(27)
Decrease (increase) in operating assets-		
Receivables	42	50
Prepayments and other current assets	8	(30)
Increase (decrease) in operating liabilities-		
Accounts payable	(43)	(23)
Accrued taxes	7	—
Other	7	(6)
Net cash provided from operating activities	303	284
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(1)	(1)
Short-term borrowings, net	—	(142)
Common stock dividend payments	(50)	(268)
Other	(1)	(2)
Net cash used for financing activities	(52)	(413)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(147)	(123)
Sales of investment securities held in trusts	57	154
Purchases of investment securities held in trusts	(63)	(161)
Loans to affiliated companies, net	(77)	(163)
Cash investments	13	12
Other	(10)	(10)
Net cash used for investing activities	(227)	(291)
Net change in cash and cash equivalents	24	(420)
Cash and cash equivalents at beginning of period	26	420
Cash and cash equivalents at end of period	$ 50	$ —

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)

(In millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 625	$ 762	$ 1,579	$ 1,973
Excise tax collections	11	15	29	39
Total revenues	636	777	1,608	2,012
OPERATING EXPENSES:				
Purchased power	331	429	849	1,127
Other operating expenses	84	126	246	279
Provision for depreciation	33	33	95	87
Amortization (deferral) of regulatory assets, net	2	(4)	30	118
General taxes	17	20	44	53
Total operating expenses	467	604	1,264	1,664
OPERATING INCOME	169	173	344	348
OTHER INCOME (EXPENSE):				
Miscellaneous income	1	4	3	9
Interest expense	(31)	(32)	(92)	(93)
Capitalized interest	—	1	1	2
Total other expense	(30)	(27)	(88)	(82)
INCOME BEFORE INCOME TAXES	139	146	256	266
INCOME TAXES	62	61	114	113
NET INCOME	$ 77	$ 85	$ 142	$ 153
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 77	$ 85	$ 142	$ 153
OTHER COMPREHENSIVE LOSS:				
Pensions and OPEB prior service costs	(6)	(6)	(18)	(17)
Other comprehensive loss	(6)	(6)	(18)	(17)
Income tax benefits on other comprehensive loss	(4)	(2)	(11)	(7)
Other comprehensive loss, net of tax	(2)	(4)	(7)	(10)
COMPREHENSIVE INCOME	$ 75	$ 81	$ 135	$ 143

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2012 and $3 in 2011	$ 250	$ 235
Affiliated companies	40	—
Other	18	17
Prepaid taxes	71	33
Other	43	19
	422	304
UTILITY PLANT:		
In service	5,124	4,872
Less — Accumulated provision for depreciation	1,797	1,743
	3,327	3,129
Construction work in progress	114	227
	3,441	3,356
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	229	219
Nuclear plant decommissioning trusts	199	193
Other	2	2
	430	414
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	526	408
Other	29	32
	2,366	2,251
	$ 6,659	$ 6,325
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 35	$ 34
Short-term borrowings-		
Affiliated companies	350	259
Accounts payable-		
Affiliated companies	1	19
Other	95	101
Accrued compensation and benefits	35	41
Customer deposits	24	24
Accrued interest	30	18
Other	29	36
	599	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	32	39
Retained earnings	173	121
Total common stockholder's equity	2,352	2,307
Long-term debt and other long-term obligations	1,711	1,736
	4,063	4,043
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	1,023	859
Power purchase contract liability	267	147
Nuclear fuel disposal costs	197	197
Retirement benefits	163	170
Asset retirement obligations	121	115
Other	226	262
	1,997	1,750
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$ 6,659	$ 6,325

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 142	$ 153
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	95	87
Amortization of regulatory assets, net	30	118
Deferred purchased power and other costs	(95)	(84)
Deferred income taxes and investment tax credits, net	156	83
Accrued compensation and retirement benefits	(31)	(12)
Pension trust contribution	—	(105)
Decrease (increase) in operating assets-		
Receivables	(57)	85
Prepaid taxes	(38)	(59)
Decrease in operating liabilities-		
Accounts payable	(24)	(60)
Accrued taxes	(6)	(1)
Accrued interest	12	12
Other	24	10
Net cash provided from operating activities	208	227
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	91	312
Redemptions and Repayments-		
Long-term debt	(24)	(23)
Common stock dividend payments	(90)	(500)
Other	—	(2)
Net cash used for financing activities	(23)	(213)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(157)	(160)
Loans to affiliated companies, net	—	177
Sales of investment securities held in trusts	376	610
Purchases of investment securities held in trusts	(387)	(624)
Other	(17)	(17)
Net cash used for investing activities	(185)	(14)
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.

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND BASIS OF PRESENTATION

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

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 nine months ended September 30, 2011, include just seven 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 nine months ended September 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. GOODWILL

On January 1, 2012, FirstEnergy adopted the amendment to the authoritative accounting guidance regarding the testing for goodwill impairment that provides the option to apply a qualitative assessment to determine whether or not it is necessary to apply the traditional two-step quantitative goodwill impairment test.

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, a likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying amount. If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing of goodwill assigned to its reporting units is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify potential goodwill impairment and measure the amount of goodwill impaired to be recognized, if any.

The 2012 annual goodwill impairment test was performed during the third quarter primarily using a qualitative assessment approach. FirstEnergy assessed economic, industry and market considerations in addition to overall financial performance of its reporting units. FirstEnergy's reporting units are consistent with its operating entities, which aggregate to reportable segments and consist of Regulated Distribution, Regulated Transmission and Competitive Energy Services. Goodwill is allocated to these reportable segments based on the original purchase price allocation for acquisitions within the various reporting units.

As of September 30, 2012, goodwill balances for the Regulated Distribution, Regulated Transmission and Competitive Energy Services segments were $5,025 million, $526 million and $893 million, respectively. It was determined that the fair values of FirstEnergy's reporting units were, more likely than not, greater than their carrying values. No further goodwill testing was completed and no impairment was recognized.

3. 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:

	Three Months Ended September 30		Nine Months Ended September 30	
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	**2012**	**2011**	**2012**	**2011**
	(In millions, except per share amounts)			
Weighted average number of basic shares outstanding	417	418	418	392
Assumed exercise of dilutive stock options and awards[1]	2	2	1	2
Weighted average number of diluted shares outstanding	419	420	419	394
Earnings Available to FirstEnergy Corp.	$ 425	$ 532	$ 918	$ 787
Basic earnings per share of common stock	$ 1.02	$ 1.27	$ 2.20	$ 2.01
Diluted earnings per share of common stock	$ 1.01	$ 1.27	$ 2.19	$ 2.00

(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 nine months ended September 30, 2012 and 2011.

4. 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 pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the nine months ended September 30, 2012, FirstEnergy made a voluntary $600 million contribution to its qualified pension plan. No additional contributions are expected to be made in 2012.

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)	**Pensions**		**OPEB**	
For the Three Months Ended September 30,	**2012**	**2011**	**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)

Net periodic costs (credits)	$ 19	$ 19	$ (45)	$ (46)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	2012	2011	2012	2011
	(In millions)			
Service cost	$ 120	$ 97	$ 9	$ 9
Interest cost	291	276	36	35
Expected return on plan assets	(363)	(332)	(27)	(30)
Amortization of prior service cost	9	12	(153)	(150)
Other adjustments (settlements, curtailments, etc)	—	7	—	—
Net periodic costs (credits)	$ 57	$ 60	$ (135)	$ (136)

Pension and OPEB obligations are allocated to the FE subsidiaries that employ 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 September 30,	2012	2011	2012	2011
	(In millions)			
FirstEnergy	$ 14	$ 14	$ (30)	$ (31)
FES	12	7	(8)	(8)
OE	(1)	(2)	(5)	(5)
JCP&L	(2)	(3)	(3)	(2)

Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	2012	2011	2012	2011
	(In millions)			
FirstEnergy	$ 41	$ 48	$ (92)	$ (97)
FES	33	21	(24)	(24)
OE	(3)	(6)	(16)	(16)
JCP&L	(5)	(8)	(7)	(7)

5. INCOME TAXES

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Significant judgment is required in determining FirstEnergy's income taxes and in evaluating tax positions taken or expected to be taken on its tax returns. 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 nine months ended September 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 Allegheny 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 nine 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 first nine months of 2011. There were no other material changes to FirstEnergy's unrecognized income tax benefits during the first nine months of 2012 or 2011.

As of September 30, 2012, it is reasonably possible that approximately $40 million of unrecognized income tax benefits may be resolved within the next twelve months, of which approximately $6 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 nine 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 nine months of 2011. During the first nine 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 September 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 nine months of 2011.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2011) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2009-2011, and additionally 2001 and 2008 for Pennsylvania. 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 2009-2011. State tax returns for tax years 2009 through 2011 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.

6. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. 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 third 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 $253 million was outstanding as of September 30, 2012; and special purpose limited liability companies of MP and PE created to issue environmental control bonds that were used to construct environmental control facilities, of which $493 million was outstanding as of September 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 nine months ended September 30, 2012, was primarily due to net income attributable to noncontrolling interests of $1 million, offset by $4 million in distributions 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, Pinesdale LLC, 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 Global Holding, the holding company for 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 that was to be constructed by PATH-WV.

On August 24, 2012, PJM officially removed the PATH project from its long-range expansion plans. Citing a slow economy for reducing the projected growth in electricity use, PJM said its updated analysis no longer indicates a need for the $2.1 billion, 275-mile transmission line to maintain grid stability. A joint venture between Allegheny and AEP, the project was suspended by PJM in February 2011. PATH expects to recover approximately $121 million of costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) over the next 5 years, of which $62 million relates to PATH-Allegheny and approximately $59 million relates to

PATH-WV. See Note 9, Regulatory Matters, of the Combined Notes to the Consolidated Financial Statements for additional information on the abandonment of PATH.

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 as of September 30, 2012. In October 2012, one of JCP&L's long-term power purchase agreements with a NUG entity ended. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities.

FirstEnergy has determined that for all but 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 FE subsidiaries during the three months ended September 30, 2012, were $19 million, $30 million and $16 million for JCP&L, PE and WP, respectively, and $46 million, $89 million and $49 million for the nine months ended September 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, during the three months ended September 30, 2011, were $44 million, $31 million, and $14 million, respectively, and $164 million, $89 million and $40 million for the nine months ended September 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 September 30, 2012, WP's reserve for this adverse purchase power commitment was $45 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.

On August 24, 2012, NGC repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $108 million. Additionally, during the third quarter of 2012, FGCO acquired certain lessor equity interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for an aggregate purchase price of approximately $95.4 million; during the fourth quarter of 2012, additional equity purchases of $37.6 million, as well as an early buyout for $23.6 million occurred.

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 as of September 30, 2012:

	Maximum Exposure	Discounted Lease Payments, net(1)	Net Exposure
		(In millions)	
FES	$ 1,339	$ 1,123	$ 216
OE	551	390	161
Other FE subsidiaries	561	326	235

(1) The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.4 billion.

7. 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, which 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 8, 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 September 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 nine months ended September 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.

FirstEnergy

Recurring Fair Value Measurements	**September 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	$ —	$ 1,012	$ —	1,012	$ —	$ 1,544	$ —	$ 1,544
Derivative assets - commodity contracts	3	257	—	260	—	264	—	264
Derivative assets - FTRs	—	—	7	7	—	—	1	1
Derivative assets - NUG contracts[1]	—	—	18	18	—	—	56	56
Equity securities[2]	367	—	—	367	259	—	—	259
Foreign government debt securities	—	60	—	60	—	3	—	3
U.S. government debt securities	—	184	—	184	—	148	—	148
U.S. state debt securities	—	314	—	314	—	314	—	314
Other[3]	124	562	—	686	49	225	—	274
Total assets	494	2,389	25	2,908	308	2,498	57	2,863
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(247)	—	(247)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(23)	(23)
Derivative liabilities - NUG contracts[1]	—	—	(300)	(300)	—	—	(349)	(349)
Derivative liabilities - LCAPP contracts[1]	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	(177)	(453)	(630)	—	(247)	(372)	(619)
Net assets (liabilities)[4]	$ 494	$ 2,212	$ (428)	$ 2,278	$ 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 $43 million and $(52) million as of September 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 and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 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
					(in millions)				
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)	(39)	(144)	(183)	—	3	3	1	(4)	(3)
Purchases	—	—	—	—	(145)	(145)	12	(10)	2
Issues	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	—	193	193	—	—	—	(7)	26	19
Transfers in (out) of Level 3	—	—	—	—	—	—	—	—	—
September 30, 2012 Balance	$ 18	$ (300)	$ (282)	$ —	$ (142)	$ (142)	$ 7	$ (11)	$ (4)

(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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (4)	Model	RTO auction clearing prices	($3.80) to $6.40	$ 0.50	Dollars/MWH
NUG Contracts	$ (282)	Model	Generation Electricity regional prices	700 to 6,748,000 $43.40 to $57.30	3,211,000 $51.90	MWH Dollars/MWH
LCAPP Contracts	$ (142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

FES

Recurring Fair Value Measurements	September 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	$ —	$ 437	$ —	$ 437	$ —	$ 1,010	$ —	$ 1,010
Derivative assets - commodity contracts	3	252	—	255	—	248	—	248
Derivative assets - FTRs	—	—	5	5	—	—	1	1
Equity securities(1)	334	—	—	334	124	—	—	124
Foreign government debt securities	—	50	—	50	—	3	—	3
U.S. government debt securities	—	21	—	21	—	7	—	7
U.S. state debt securities	—	—	—	—	—	5	—	5
Other(2)	—	396	—	396	—	132	—	132
Total assets	337	1,156	5	1,498	124	1,405	1	1,530
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(234)	—	(234)
Derivative liabilities - FTRs	—	—	(7)	(7)	—	—	(7)	(7)
Total liabilities	—	(177)	(7)	(184)	—	(234)	(7)	(241)
Net assets (liabilities)(3)	$ 337	$ 979	$ (2)	$ 1,314	$ 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 $47 million and $(58) million as of September 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 September 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	(2)	(1)
Purchases	8	(7)	1
Issues	—	—	—
Sales	—	—	—

Settlements	(5)	9	4
Transfers in (out) of Level 3	—	—	—
September 30, 2012 Balance	$ 5	$ (7)	$ (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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (2)	Model	RTO auction clearing prices	($3.80) to $6.40	$0.30	Dollars/ MWH

OE

Recurring Fair Value Measurements	September 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 and $1 million as of September 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	September 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	$ —	$ 139	$ —	$ 139	$ —	$ 144	$ —	$ 144
Derivative assets - NUG contracts(1)	—	—	1	1	—	—	4	4
Equity securities(2)	—	—	—	—	30	—	—	30
Foreign government debt securities	—	2	—	2	—	—	—	—
U.S. government debt securities	—	8	—	8	—	2	—	2
U.S. state debt securities	—	230	—	230	—	219	—	219
Other(3)	—	48	—	48	—	15	—	15
Total assets	—	427	1	428	30	380	4	414
Liabilities								
Derivative liabilities - NUG contracts(1)	—	—	(125)	(125)	—	—	(147)	(147)
Derivative liabilities - LCAPP contracts(1)	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	—	(267)	(267)	—	—	(147)	(147)
Net assets (liabilities)(4)	$ —	$ 427	$ (266)	$ 161	$ 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 $1 million and $2 million as of September 30, 2012 and December 31, 2011 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 NUG and LCAPP contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2012 and December 31, 2011:

	NUG Contracts[1]			LCAPP Contracts[1]		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
			(in millions)			
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)	(3)	(17)	(20)	—	3	3
Purchases	—	—	—	—	(145)	(145)
Issues	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	39	39	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
September 30, 2012 Balance	$ 1	$ (125)	$(124)	$ —	$ (142)	$(142)

(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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
NUG Contracts	$ (124)	Model	Generation Electricity regional prices	95,000 to 1,324,000 $45.50 to $59.50	405,000 $54.10	MWH Dollars/ MWH
LCAPP Contracts	$ (142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	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 OTTI. 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 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 and NUG trusts as of September 30, 2012 and December 31, 2011:

	September 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								
FirstEnergy	$ 1,529	$ 37	$ —	$ 1,566	$ 1,980	$ 25	$ —	$ 2,005
FES	500	8	—	508	1,012	13	—	1,025
OE	137	—	—	137	134	—	—	134
JCP&L	364	13	—	377	356	7	—	363
Equity securities								
FirstEnergy	$ 320	$ 46	$ —	$ 366	$ 222	$ 36	$ —	$ 258
FES	295	38	—	333	104	20	—	124
JCP&L	—	—	—	—	27	3	—	30

(1) Excludes short-term cash investments: FE Consolidated - $596 million; FES - $443 million; OE - $3 million; JCP&L - $51 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 nine months ended September 30, 2012 and 2011 were as follows:

Three Months Ended				
September 30, 2012	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
	(In millions)			
FirstEnergy	$ 1,751	$ 81	$ (32)	$ 18
FES	1,059	60	(23)	10
OE	—	—	—	1
JCP&L	211	6	(2)	4
September 30, 2011	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
	(In millions)			
FirstEnergy	$ 1,974	$ 98	$ (38)	$ 20
FES	1,100	52	(19)	9
OE	134	7	(1)	1
JCP&L	234	11	(4)	5

Nine Months Ended				
September 30, 2012	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
		(In millions)		
FirstEnergy	$ 2,133	$ 118	$ (67)	$ 51
FES	1,167	85	(48)	27
OE	57	—	—	2
JCP&L	376	8	(4)	11
September 30, 2011	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
		(In millions)		
FirstEnergy	$ 3,678	$ 220	$ (83)	$ 72
FES	1,613	74	(42)	41
OE	154	7	(1)	3
JCP&L	610	37	(10)	13

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 September 30, 2012 and December 31, 2011:

	September 30, 2012			December 31, 2011		
	Cost Basis	**Unrealized Gains**	**Fair Value**	**Cost Basis**	**Unrealized Gains**	**Fair Value**
			(In millions)			
Debt Securities						
FirstEnergy	$ 210	$ 58	$ 268	$ 402	$ 50	$ 452
OE	148	33	181	163	21	184

Investments in emission allowances, employee benefit trusts and cost and equity method investments totaling $709 million as of September 30, 2012, and $693 million as of December 31, 2011, are excluded from the amounts reported above.

Notes Receivable

FES has a long-term note receivable of $4 million as of September 30, 2012 that matures in December 2013. Due to the short duration of this note, it is recorded at cost which approximates fair value.

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. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts, as of September 30, 2012 and December 31, 2011:

	September 30, 2012		December 31, 2011	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
		(In millions)		
FirstEnergy	$ 16,942	$ 19,677	$ 17,165	$ 19,320
FES	4,133	4,494	3,675	3,931
OE	1,157	1,500	1,157	1,434
JCP&L	1,753	2,092	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 September 30, 2012 and December 31, 2011.

8. DERIVATIVE INSTRUMENTS

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

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 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 instruments previously designated to be in a cash flow hedging relationship totaled $13 million and $19 million as of September 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 $2 million and less than $1 million of income during the three months ended September 30, 2012 and 2011, respectively, and $6 million of income and $18 million of loss during the nine months ended September 30, 2012 and 2011, respectively. Approximately $8 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 September 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 $72 million as of September 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 September 30, 2012 and 2011, respectively, and $7 million and $9 million during the nine months ended September 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 September 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 $85 million as of September 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 and $5 million during the three months ended September 30, 2012 and 2011, respectively, and $17 million and $16 million during the nine months ended September 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 September 30, 2012, FirstEnergy's net asset position under commodity derivative contracts was $83 million, which related to FES and AE Supply positions. Under these commodity derivative contracts, FES posted $33 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $38 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 September 30, 2012, an adverse 10% change in commodity prices would decrease net income by approximately $18 million during the next twelve months.

Interest Rate Swaps

FirstEnergy has used 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 were 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. Changes in fair value of the forward starting swap agreements were recorded in net income on a market-to-market basis. 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. In August 2012, FirstEnergy terminated all of the forward starting swap agreements that were executed in the second quarter, resulting in a net gain, recorded as a reduction to interest expense, and cash proceeds of approximately $6 million.

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 with a corresponding regulatory asset. 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			Derivative Liabilities		
	Fair Value			Fair Value	
	September 30, 2012	December 31, 2011		September 30, 2012	December 31, 2011
	(In millions)			*(In millions)*	
Power Contracts			Power Contracts		
Current Assets	$ 178	$ 185	Current Liabilities	$ (146)	$ (196)
Noncurrent Assets	79	79	Noncurrent Liabilities	(31)	(51)
FTRs			FTRs		
Current Assets	7	1	Current Liabilities	(9)	(22)
Noncurrent Assets	—	—	Noncurrent Liabilities	(2)	(1)
NUGs	18	56	NUGs	(300)	(349)
LCAPP	—	—	LCAPP	(142)	—
Other Current Assets	3	—	Other Current Liabilities	—	—
	$ 285	$ 321		$ (630)	$ (619)

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

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	33	38	(5)	MWH
FTRs	67	—	67	MWH
NUGs	16	—	16	MWH
LCAPP	408	—	408	MW
Natural Gas	16	—	16	BTUs

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

	Three Months Ended September 30				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$ (2)	$ —	$ —	$ —	$ (2)
2011					
Gain (Loss) Recognized in AOCI (Effective Portion)	$ —	$ —	$ —	$ —	$ —
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain (Loss) Recognized in:					
Other Operating Expense	$ 7	$ (5)	$ —	$ —	$ 2
Interest Expense	—	—	20	—	20
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (27)	$ —	$ —	$ —	$ (27)
Revenues	46	6	—	—	52
Other Operating Expense	—	(10)	—	—	(10)
Fuel Expense	—	—	—	3	3
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$ 27	$ —	$ —	$ —	$ 27
Revenues	3	—	—	—	3
Other Operating Expense	(11)	(9)	1	—	(19)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (5)	$ —	$ —	$ —	$ (5)
Revenues	(39)	20	(1)	—	(20)
Other Operating Expense	—	(22)	—	—	(22)

	Nine Months Ended September 30				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
	(In millions)				
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$ (6)	$ —	$ —	$ —	$ (6)
2011					
Gain Recognized in AOCI (Effective Portion)	$ 4	$ —	$ 1	$ —	$ 5
Effective Gain (Loss) Reclassified to:					
Purchased Power Expense	16	—	—	—	16
Revenues	(12)	—	—	—	(12)
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain Recognized in:					
Other Operating Expense	$ 69	$ 12	$ —	$ 3	$ 84
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (248)	$ —	$ —	$ —	$ (248)
Revenues	260	18	—	—	278
Other Operating Expense	—	(51)	—	—	(51)
Fuel Expense	—	—	—	2	2
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$ 88	$ —	$ —	$ —	$ 88
Revenues	(1)	—	—	—	(1)
Other Operating Expense	(65)	2	2	—	(61)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (41)	$ —	$ —	$ —	$ (41)
Revenues	(69)	36	(2)	—	(35)
Other Operating Expense	—	(77)	—	—	(77)

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

	Three Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
			(In millions)		
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Gain (Loss) on Derivative Instrument	$ (50)	$ 3	$ —	$ —	$ (47)
Realized Gain (Loss) on Derivative Instrument	61	—	(1)	—	60
2011					
Unrealized Loss on Derivative Instrument	$ (89)	$ —	$ (3)	$ —	$ (92)
Realized Gain (Loss) on Derivative Instrument	53	—	(3)	—	50

	Nine Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
			(In millions)		
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Loss on Derivative Instrument	$(183)	$ (142)	$ —	$ —	$(325)
Realized Gain on Derivative Instrument	194	—	7	—	201
2011					
Unrealized Loss on Derivative Instrument	$(325)	$ —	$ —	$ —	$(325)
Realized Gain (Loss) on Derivative Instrument	187	—	(4)	(10)	173

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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 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 July 1, 2012	$ (293)	$ (145)	$ —	$ —	$ (438)
Additions/Change in value of existing contracts	(50)	3	—	—	(47)
Settled contracts	61	—	(1)	—	60
Outstanding net asset (liability) as of September 30, 2012	$ (282)	$ (142)	$ (1)	$ —	$ (425)
Outstanding net asset (liability) as of July 1, 2011	$ (447)	$ —	$ 2	$ —	$ (445)
Additions/Change in value of existing contracts	(89)	—	(3)	—	(92)
Settled contracts	53	—	(3)	—	50

Outstanding net asset (liability) as of September 30, 2011	$ (483)	$ —	$ (4)	$ —	$ (487)

Derivatives Not in a Hedging Relationship with Regulatory Offset[(1)]	Nine Months Ended September 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	(183)	(142)	—	—	(325)
Settled contracts	194	—	7	—	201
Outstanding net asset (liability) as of September 30, 2012	$ (282)	$ (142)	$ (1)	$ —	$ (425)
Outstanding net asset (liability) as of January 1, 2011	$ (345)	$ —	$ —	$ 10	$ (335)
Additions/Change in value of existing contracts	(325)	—	—	—	(325)
Settled contracts	187	—	(4)	(10)	173
Outstanding net asset (liability) as of September 30, 2011	$ (483)	$ —	$ (4)	$ —	$ (487)

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

9. REGULATORY MATTERS

STATE REGULATION

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

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. 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. 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 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. On December 22, 2011, the MDPSC 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.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted on September 13 and 14, 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards that the MDPSC approved on April 17, 2012, and which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. The panel's report has been referred to the MDPSC for action.

NEW JERSEY

JCP&L currently provides BGS for retail customers that do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates. The most recent BGS auction results, for supply that commenced on 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, 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. Due to Hurricane Sandy, JCP&L requested an extension and will file a base rate case using a historic 2011 test year by December 1, 2012.

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 consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. The NJBPU solicited written comments on the report from stakeholders to be submitted by September 20, 2012, and JCP&L submitted written comments on that date. The NJBPU has not specified the action that will 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. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing.

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at 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 provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in 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 RECs 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.

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. 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 by the PUCO and the subsequent appeal was dismissed by the Supreme Court of Ohio. 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. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period. Hearings were held the week of October 22, 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 were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/ performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. The PUCO has set this matter for hearing on February 19, 2013. 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. The Ohio companies are in the midst of a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks 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 EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 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. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies made a compliance filing on September 6, 2012, seeking finalization of their procurement and rate design plans, and the PPUC issued a Secretarial Letter on November 8, 2012 approving the compliance filing. The PPUC entered an order on September 27, 2012, disposing of the Petitions for Reconsideration or Clarification filed by the Pennsylvania Companies and other parties. The Pennsylvania Companies were granted an extension to file revised proposals on the retail market enhancements by November 14, 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's and PN's TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which was denied on February 28, 2012, and ME and PN also filed 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 the amended complaint on September 15, 2011, to which ME and PN responded. On September 26, 2012, United States District Court Judge Gardner entered an order dismissing the PPUC's motion to dismiss without prejudice. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. On October 9, 2012, the Supreme Court denied that petition. Accordingly, ME and PN intend to 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 could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 1, 2012, a phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. A hearing on the level of the Pennsylvania Companies' respective Phase II energy efficiency targets as established by the PPUC was held on October 19, 2012. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator.

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 SMIP, 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 AE 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 EGSs; 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. On September

27, 2012, the PPUC issued a Secretarial Letter and an "RMI End State Proposal" discussion document. PPUC staff hosted a conference call on October 17, 2012, and a Tentative Order was entered by the PPUC on November 8, 2012, seeking comments, that are due within 30 days, regarding the end state of default service and related issues.

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. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

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 February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all alternative and RECs associated with the 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 on November 22, 2011, granting ownership of all RECs produced by the facilities to MP, and holding that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility formed under PURPA owns the RECs associated with that purchase. 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 filed complaints at FERC alleging the WVPSC order violated PURPA and requested that 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 order 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, which was denied by FERC on September 20, 2012. The City of 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. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated by September 1, 2012.

The WVPSC has proceedings for each West Virginia electric utility to establish reliability targets for distribution performance. The parties entered into a settlement in September 2012 resolving all issues and establishing performance targets with more stringent targets beginning in 2014. The settlement is under review by the WVPSC.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012.

The West Virginia ENEC fuel case was filed by MP and PE at the WVPSC in August 2012 with a projected over-recovery of

approximately $66 million under current rates for the next year, January 1, 2013 through December 31, 2013. MP and PE proposed no change in overall rates on January 1, 2013; however, MP and PE proposed establishing a separate regulatory liability for the difference between the recommended 2013 ENEC rates and the current ENEC rates. This estimated $66 million liability would be used to offset the rate relief MP and PE will seek in a filing later this year to become effective with the completion of a proposed generation resource transaction, which MP and PE will propose to complete by mid-2013. Discovery in the ENEC proceeding is underway and a hearing is expected in December 2012.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE plan to file a Petition for Approval of a Generation Resource Transaction with the WVPSC in November 2012 that involves a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement what we believe to be a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make additional electricity and capacity purchases from the spot market which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to increase due to an increase in annual load growth of approximately 1.4%.

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. 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.

During September 2012, RFC performed a routine compliance audit of certain parts of FirstEnergy's bulk-power systems and generally found the audited systems and processes to be in full compliance with all the audited reliability standards.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" 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 LSEs 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. FirstEnergy's request for rehearing remains pending before FERC.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays (or usage based) and 50% postage stamp (or socialization) to be effective for RTEP projects approved by the PJM Board on and after the effective date of the compliance filing. The filing is pending before FERC. Filings to demonstrate compliance with the interregional cost allocation principles of the order must be submitted to FERC by April 2013.

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. Finally, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to loads in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI is considering whether to appeal FERC's ruling on the "legacy RTEP" issue. FirstEnergy has also appealed the issue of legacy RTEP to the Seventh Circuit Court of Appeals. Although there can be no assurance, success in the appeal could terminate the ATSI zone's responsibility for legacy RTEP charges.

ATSI's filings and requests for rehearing on certain of these matters, as well as the pleadings submitted by parties that oppose ATSI's position are currently pending before FERC. Finally, on August 22, 2012, FERC approved 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.

The 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 $16 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 may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings and appeals. These further proceedings can be divided into two classes: litigation related to the MISO's generic MVP cost allocation proposal; and litigation related to the MISO's "Schedule 39" tariff that purports to charge the MVP costs against ATSI.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of the FERC's orders that address the generic MVP tariffs 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 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 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. The hearings will start in April 2013.

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 LSEs 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. On September 10, 2012, PJM submitted the compliance filing. On October 17, 2012, FERC accepted the PJM compliance filing, resolving this matter.

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 had previously remanded one of those proceedings to FERC. In March 2010, the FERC ALJ 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 20, 2012, the California Parties appealed the FERC's decision back to the Ninth Circuit Court of Appeals. On July 19, 2012, the Ninth Circuit Court of Appeals issued an order declining to consolidate the appeal with other pending appeals regarding California refund claims, suspending briefing, and directing interested parties to intervene by August 31, 2012. AE Supply filed an intervention on August 28, 2012. On September 6, 2012, the Ninth Circuit issued an order granting AE Supply's intervention and continuing the suspension of the briefing schedule ordered on July 19, 2012. The timing of further action by the Ninth Circuit is unknown.

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, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this additional complaint. AE Supply filed a motion to dismiss this second complaint, which 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 20, 2012, the California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. In addition, on July 13, 2012, the California Attorney General requested rehearing of the June 13, 2012 order. On July 19, 2012, the Ninth Circuit consolidated the June 20, 2012 appeal with other pending appeals related to California refund claims, referred the case to the Circuit Mediator, and stayed the proceedings pending further order. On August 7, 2012, FERC rejected the California Attorney General's July 13, 2012 request for rehearing. On August 16, 2012, the California Attorney General appealed the August 7, 2012 order to the Ninth Circuit. On August 29, 2012, the Ninth Circuit consolidated the August 16, 2012 appeal with the aforementioned

cases and continued the stay pending further order. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers officially canceled the project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, these companies requested authorization from FERC to recover these costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) from PJM customers over the next 5 years. Several parties have protested the request and a FERC decision is pending.

On September 20, 2012, FERC set for hearing formal challenges to the PATH formula rate annual updates submitted in June 2010 and June 2011. These challenges seek a disallowance of approximately $6.6 million in costs for the project. Settlement judge procedures are pending. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

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, which 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. FirstEnergy submitted comments on August 10, 2012, and reply comments 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.

10. COMMITMENTS, GUARANTEES AND CONTINGENCIES

GUARANTEES AND OTHER ASSURANCES

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

As of September 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).

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, fuel, and emission 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 September 30, 2012, FES has posted collateral of $73 million. The Regulated Distribution segment has posted collateral of $21 million.

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

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3 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 table discloses the additional credit contingent contractual obligations as of September 30, 2012:

Collateral Provisions	**FES**	**AE Supply**	**Utilities**	**Total**
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 397	$ 6	$ 42	$ 445
BB+/Ba1 Credit Ratings	$ 450	$ 6	$ 61	$ 517
Full impact of credit contingent contractual obligations	$ 671	$ 72	$ 76	$ 819

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of September 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 $40 million and $11 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

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

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

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility by December 31, 2013 on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, of 4% through December 31, 2012, 5% from January 1 through December 31, 2013 and, thereafter, a rate per annum equal to the then current Merrill Lynch High Yield 100 index, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

ENVIRONMENTAL MATTERS

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

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, 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 vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In 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. On July 27, 2012, ME filed a motion for summary judgment on plaintiff's remaining 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. On November 1, 2012, the other defendants and the plaintiffs filed motions for summary judgment regarding various claims. FirstEnergy believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued 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 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 and their opening appellate brief is due November 14, 2012. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

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

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received 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. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities 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 December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. The Court ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. 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. 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 approximately $975 million and other changes to FirstEnergy's operations may result.

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, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. 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. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. During the nine months ended September 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) 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. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated 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. The EHB dismissed these appeals on August 29, 2012, after a settlement in the form of a Consent Decree was entered by the Commonwealth Court of Pennsylvania on August 16, 2012, resolving the disputes concerning the Hatfield's Ferry Plant NPDES permit, including elimination of the TDS limit and deferring the lower sulphate limits until July 2018.

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 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 $150 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In 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. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. On August 14, 2012, a Consent Decree was entered by the Court resolving these claims. MP is currently seeking relief from the arsenic limits through a 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 proposed Consent Decree, if entered by the court, 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 proposed Consent Decree would also require payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. The Bruce Mansfield Plant 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 FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of September 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 $123 million (including $86 million applicable to JCP&L) have been accrued through September 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 September 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 SAMA analysis. On July 26, 2012, FENOC filed a motion for Summary Disposition on the remaining admitted contention on the SAMA analysis for Davis-Besse. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the longitudinal cracking of the Davis-Besse shield building discussed below. The intervenors supplemented their petition for a contention on the shield building on multiple occasions. The ASLB scheduled a November 5 and 6, 2012 oral argument to consider FENOC's motion for summary disposition, the intervenors request for a new contention on the Shield Building.

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. On July 9, 2012, the intervenors petitioned the ASLB for a new contention on the environmental impacts of temporary spent fuel storage by Davis-Besse due to the lack of a repository and the disposal of these wastes. 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. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

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. The NRC Staff began its 95002 inspection at the Perry plant on August 27, 2012. 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.

On September 17, 2012, FENOC announced a plan to expand used nuclear fuel storage capacity at its two unit Beaver Valley Power Station. Under the plan, above-ground, airtight steel and concrete canisters will be installed to provide cooling, through natural air circulation, to used fuel assemblies. Initial installation will consist of six canisters and up to 47 additional canisters will be added as needed. Construction of the fuel storage system is scheduled to begin in fall 2012, with completion planned for 2014. Certain costs incurred by FirstEnergy for this project are expected to be reimbursable by the DOE under a January 2012 settlement. Due to a change in NRC regulations, FirstEnergy will be required to independently fund the radiological decommissioning of its independent spent fuel storage facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term 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, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP will file a Petition for Allowance of Appeal with the Pennsylvania Supreme Court within 30 days. A ruling by the Supreme Court on whether it will hear the case is expected in the second quarter of 2013. 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 heard arguments on the appeal in September, 2012.

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 9, 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.

Storm Cost Contingency

In late October 2012, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Sandy. Approximately 2.3 million customers were affected by outages in New Jersey, Pennsylvania, West Virginia, Ohio and Maryland. Nearly 20,000 professionals, including employees from FirstEnergy's Utilities and outside contractors and utility workers have worked to restore service to customers who lost power following the devastating storm. As of November 7, 2012, more than 95% of customers in Pennsylvania, Ohio, West Virginia and Maryland who were affected by the storm had electric service restored. In New Jersey, where the storm damage was most severe, nearly 1.2 million customers were affected by the storm. As of November 7, 2012, 85% of affected customers in New Jersey have been restored. Storm costs are expected to exceed $500 million, of which approximately 95% is expected to be capitalized or deferred for future recovery from customers. Final storm costs will be determined during the fourth quarter of 2012.

11. 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 nine months ended September 30, 2012 and 2011, Consolidating Balance Sheets as of September 30, 2012 and December 31, 2011, and Consolidating Statements of Cash Flows for the nine months ended September 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 September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 1,523	$ 617	$ 395	$ (978)	$ 1,557
OPERATING EXPENSES:					
Fuel	—	248	55	—	303
Purchased power from affiliates	1,042	—	67	(978)	131
Purchased power from non-affiliates	499	—	—	—	499
Other operating expenses	130	79	122	12	343
Provision for depreciation	1	30	41	(1)	71
General taxes	20	10	5	—	35
Total operating expenses	1,692	367	290	(967)	1,382
OPERATING INCOME (LOSS)	(169)	250	105	(11)	175
OTHER INCOME (EXPENSE):					
Investment income	1	5	37	(5)	38
Miscellaneous income, including net income from equity investees	317	—	—	(316)	1
Interest expense — affiliates	(5)	(2)	(1)	5	(3)
Interest expense — other	(25)	(27)	(15)	16	(51)
Capitalized interest	—	1	8	—	9
Total other income (expense)	288	(23)	29	(300)	(6)
INCOME BEFORE INCOME TAXES	119	227	134	(311)	169
INCOME TAXES (BENEFITS)	18	(11)	59	2	68
NET INCOME	$ 101	$ 238	$ 75	$ (313)	$ 101
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 101	$ 238	$ 75	$ (313)	$ 101
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available for sale securities	(2)	—	(1)	1	(2)
Other comprehensive loss	(9)	(4)	(1)	5	(9)
Income tax benefits on other comprehensive loss	(3)	(2)	—	2	(3)

Other comprehensive loss, net of tax	(6)	(2)	(1)	3	(6)
COMPREHENSIVE INCOME	$ 95	$ 236	$ 74	$ (310)	$ 95

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,443	$ 1,795	$ 1,262	$ (2,971)	$ 4,529
OPERATING EXPENSES:					
Fuel	—	824	154	—	978
Purchased power from affiliates	3,163	—	189	(2,971)	381
Purchased power from non-affiliates	1,420	—	—	—	1,420
Other operating expenses	313	271	410	37	1,031
Provision for depreciation	3	90	114	(4)	203
General taxes	60	28	16	—	104
Total operating expenses	4,959	1,213	883	(2,938)	4,117
OPERATING INCOME (LOSS)	(516)	582	379	(33)	412
OTHER INCOME (EXPENSE):					
Investment income	2	14	49	(15)	50
Miscellaneous income, including net income from equity investees	854	19	—	(848)	25
Interest expense — affiliates	(14)	(5)	(3)	15	(7)
Interest expense — other	(72)	(79)	(36)	47	(140)
Capitalized interest	—	3	24	—	27
Total other income (expense)	770	(48)	34	(801)	(45)
INCOME BEFORE INCOME TAXES	254	534	413	(834)	367
INCOME TAXES (BENEFITS)	32	(19)	124	8	145
NET INCOME	$ 222	$ 553	$ 289	$ (842)	$ 222
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 222	$ 553	$ 289	$ (842)	$ 222
OTHER COMPREHENSIVE INCOME					
Pensions and OPEB prior service costs	(2)	(1)	—	1	(2)
Amortized loss on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available for sale securities	11	—	12	(12)	11
Other comprehensive income (loss)	3	(1)	12	(11)	3

Income taxes (benefits) on other comprehensive income (loss)	1	(1)	5	(4)	1
Other comprehensive income, net of tax	2	—	7	(7)	2
COMPREHENSIVE INCOME	$ 224	$ 553	$ 296	$ (849)	$ 224

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 1,445	$ 686	$ 371	$ (1,035)	$ 1,467
OPERATING EXPENSES:					
Fuel	6	323	57	—	386
Purchased power from affiliates	1,031	4	55	(1,035)	55
Purchased power from non-affiliates	330	(2)	—	—	328
Other operating expenses	162	94	122	12	390
Provision for depreciation	1	33	36	(1)	69
General taxes	19	9	3	—	31
Impairment of long-lived assets	—	2	—	—	2
Total operating expenses	1,549	463	273	(1,024)	1,261
OPERATING INCOME (LOSS)	(104)	223	98	(11)	206
OTHER INCOME (EXPENSE):					
Investment income	—	—	28	—	28
Miscellaneous income, including net income from equity investees	196	16	—	(203)	9
Interest expense — affiliates	—	(1)	(1)	—	(2)
Interest expense — other	(24)	(26)	(16)	15	(51)
Capitalized interest	—	3	5	—	8
Total other income (expense)	172	(8)	16	(188)	(8)
INCOME BEFORE INCOME TAXES	68	215	114	(199)	198
INCOME TAXES (BENEFITS)	(52)	83	45	2	78
NET INCOME	$ 120	$ 132	$ 69	$ (201)	$ 120
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 120	$ 132	$ 69	$ (201)	$ 120
OTHER COMPREHENSIVE LOSS					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available for sale securities	(22)	—	(22)	22	(22)

Other comprehensive loss	(28)	(4)	(22)	26	(28)
Income tax benefits on other comprehensive loss	(11)	(2)	(9)	11	(11)
Other comprehensive loss, net of tax	(17)	(2)	(13)	15	(17)
COMPREHENSIVE INCOME	$ 103	$ 130	$ 56	$ (186)	$ 103

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Nine Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,087	$ 1,964	$ 1,233	$ (3,133)	$ 4,151
OPERATING EXPENSES:					
Fuel	13	883	149	—	1,045
Purchased power from affiliates	3,118	15	189	(3,133)	189
Purchased power from non-affiliates	959	(5)	—	—	954
Other operating expenses	483	313	435	37	1,268
Provision for depreciation	3	96	112	(4)	207
General taxes	46	28	17	—	91
Impairment of long-lived assets	—	22	—	—	22
Total operating expenses	4,622	1,352	902	(3,100)	3,776
OPERATING INCOME (LOSS)	(535)	612	331	(33)	375
OTHER INCOME (EXPENSE):					
Investment income	1	1	48	—	50
Miscellaneous income, including net income from equity investees	570	18	—	(571)	17
Interest expense — affiliates	(1)	(2)	(2)	—	(5)
Interest expense — other	(72)	(82)	(49)	47	(156)
Capitalized interest	—	13	15	—	28
Total other income (expense)	498	(52)	12	(524)	(66)
INCOME (LOSS) BEFORE INCOME TAXES	(37)	560	343	(557)	309
INCOME TAXES (BENEFITS)	(231)	208	131	7	115
NET INCOME	$ 194	$ 352	$ 212	$ (564)	$ 194
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 194	$ 352	$ 212	$ (564)	$ 194
OTHER COMPREHENSIVE LOSS					
Pensions and OPEB prior service costs	(14)	(12)	—	12	(14)
Amortized gain on derivative hedges	4	—	—	—	4
Change in unrealized gain on available for sale securities	(7)	—	(7)	7	(7)

Other comprehensive loss	(17)	(12)	(7)	19	(17)
Income tax benefits on other comprehensive loss	(7)	(6)	(3)	9	(7)
Other comprehensive loss, net of tax	(10)	(6)	(4)	10	(10)
COMPREHENSIVE INCOME	$ 184	$ 346	$ 208	$ (554)	$ 184

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 3	$ —	$ —	$ 3
Receivables-					
Customers	485	—	—	—	485
Affiliated companies	362	410	238	(608)	402
Other	63	15	25	—	103
Notes receivable from affiliated companies	153	2,061	406	(2,182)	438
Materials and supplies, at average cost	66	257	210	—	533
Derivatives	209	—	—	—	209
Prepayments and other	85	24	27	1	137
	1,423	2,770	906	(2,789)	2,310
PROPERTY, PLANT AND EQUIPMENT:					
In service	89	5,730	6,204	(385)	11,638
Less — Accumulated provision for depreciation	31	1,888	2,578	(185)	4,312
	58	3,842	3,626	(200)	7,326
Construction work in progress	32	203	820	—	1,055
	90	4,045	4,446	(200)	8,381
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,286	—	1,286
Investment in affiliated companies	6,555	—	—	(6,555)	—
Other	5	11	—	—	16
	6,560	11	1,286	(6,555)	1,302
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	270	—	(270)	—
Customer intangibles	114	—	—	—	114
Goodwill	24	—	—	—	24
Property taxes	—	20	23	—	43
Unamortized sale and leaseback costs	—	—	—	111	111
Derivatives	78	—	—	—	78
Other	127	163	2	(111)	181
	343	453	25	(270)	551
	$ 8,416	$ 7,279	$ 6,663	$ (9,814)	$ 12,544
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 565	$ 529	$ (21)	$ 1,074
Short-term borrowings-					
Affiliated companies	2,048	135	—	(2,183)	—
Accounts payable-					

Affiliated companies	618	311	463	(605)	787
Other	82	92	—	—	174
Accrued taxes	49	19	19	(4)	83
Derivatives	153	—	—	—	153
Other	50	154	24	16	244
	3,001	1,276	1,035	(2,797)	2,515
CAPITALIZATION:					
Total equity	3,802	3,651	2,886	(6,537)	3,802
Long-term debt and other long-term obligations	1,482	1,976	845	(1,218)	3,085
	5,284	5,627	3,731	(7,755)	6,887
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	900	900
Accumulated deferred income taxes	39	—	624	(162)	501
Asset retirement obligations	—	29	921	—	950
Retirement benefits	35	148	—	—	183
Lease market valuation liability	—	87	—	—	87
Other	57	112	352	—	521
	131	376	1,897	738	3,142
	$ 8,416	$ 7,279	$ 6,663	$ (9,814)	$ 12,544

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 Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (971)	$ 683	$ 799	$ (10)	$ 501
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	317	243	—	560
Short-term borrowings, net	982	49	—	(1,028)	3
Redemptions and Repayments-					
Long-term debt	—	(169)	(87)	10	(246)
Short-term borrowings, net	—	—	(32)	32	—
Other	(1)	(6)	(2)	—	(9)
Net cash provided from financing activities	981	191	122	(986)	308
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(10)	(175)	(350)	—	(535)
Nuclear fuel	—	—	(207)	—	(207)
Proceeds from asset sales	—	17	—	—	17
Sales of investment securities held in trusts	—	—	1,167	—	1,167
Purchases of investment securities held in trusts	—	—	(1,194)	—	(1,194)
Loans to affiliated companies, net	1	(715)	(337)	996	(55)
Other	(1)	(5)	—	—	(6)
Net cash used for investing activities	(10)	(878)	(921)	996	(813)
Net change in cash and cash equivalents	—	(4)	—	—	(4)
Cash and cash equivalents at beginning of period	—	7	—	—	7
Cash and cash equivalents at end of period	$ —	$ 3	$ —	$ —	$ 3

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Nine Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (367)	$ 539	$ 374	$ (9)	$ 537
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	140	107	—	247
Short-term borrowings, net	750	59	25	(834)	—
Redemptions and Repayments-					
Long-term debt	(136)	(351)	(313)	9	(791)
Short-term borrowings, net	—	—	—	(12)	(12)
Other	(8)	(1)	(2)	1	(10)
Net cash provided from (used for) financing activities	606	(153)	(183)	(836)	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8)	(143)	(257)	—	(408)
Nuclear fuel	—	—	(65)	—	(65)
Proceeds from asset sales	9	510	—	—	519
Sales of investment securities held in trusts	—	—	1,613	—	1,613
Purchases of investment securities held in trusts	—	—	(1,654)	—	(1,654)
Loans to affiliated companies, net	(228)	(732)	172	845	57
Other	(12)	(24)	—	—	(36)
Net cash used for investing activities	(239)	(389)	(191)	845	26
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

12. SEGMENT INFORMATION

During 2012, FirstEnergy completed the integration of AE into its IT business networks and financial systems. An important element of this system integration was the capability of modifying 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 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 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 Allegheny 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 facilities owned and operated by certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and transmission companies (ATSI, TrAIL and PATH). Its revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. These revenues are derived from providing transmission services pursuant to the PJM Open Access Transmission Tariff to electric energy providers, power marketers and revenue from operating the FirstEnergy transmission facilities. Its results reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment controls approximately 17,000 MWs of capacity, excluding approximately 2,700 MWs from unregulated plants recently deactivated or planned to be deactivated (see Note 9, 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)			
September 30, 2012						
External revenues	$ 2,438	$ 187	$ 1,719	$ (30)	$ (3)	$ 4,311
Internal revenues	—	—	210	—	(210)	—
Total revenues	2,438	187	1,929	(30)	(213)	4,311
Depreciation and amortization	202	28	105	8	—	343
Investment income	20	—	36	(1)	(16)	39
Net interest charges	132	22	62	(4)	—	212
Income taxes	168	35	76	(9)	39	309
Net income*	286	59	129	(11)	(38)	425
Total assets	26,122	4,519	16,846	1,251	—	48,738
Total goodwill	5,025	526	893	—	—	6,444
Property additions	308	47	412	8	—	775
September 30, 2011						
External revenues	$ 2,864	$ 181	$ 1,714	$ (40)	$ (12)	$ 4,707
Internal revenues	1	—	315	—	(304)	12
Total revenues	2,865	181	2,029	(40)	(316)	4,719
Depreciation and amortization	273	31	110	5	—	419
Investment income	28	—	28	—	(8)	48
Net interest charges	133	23	73	21	—	250
Income taxes	164	32	142	(23)	10	325
Net income	280	56	242	(40)	(8)	530
Total assets	26,802	4,246	16,809	816	—	48,673
Total goodwill	5,025	526	877	—	—	6,428
Property additions	234	80	186	—	—	500
Nine Months Ended						
September 30, 2012						
External revenues	$ 6,857	$ 557	$ 4,942	$ (78)	$ (22)	$ 12,256
Internal revenues	—	—	686	—	(684)	2
Total revenues	6,857	557	5,628	(78)	(706)	12,258
Depreciation and amortization	636	89	307	25	—	1,057
Investment income	62	1	48	(1)	(47)	63
Net interest charges	396	68	175	57	—	696
Income taxes	355	101	173	(49)	78	658
Net income*	603	171	295	(82)	(68)	919
Total assets	26,122	4,519	16,846	1,251	—	48,738
Total goodwill	5,025	526	893	—	—	6,444
Property additions	751	169	715	51	—	1,686
September 30, 2011						

External revenues	$ 7,496	$ 476	$ 4,450	$ (93)	$ (30)	$ 12,299
Internal revenues	1	—	976	—	(921)	56
Total revenues	7,497	476	5,426	(93)	(951)	12,355
Depreciation and amortization	746	81	307	19	—	1,153
Investment income	76	—	49	1	(26)	100
Net interest charges	389	64	195	60	—	708
Income taxes	322	79	163	(53)	39	550
Net income	547	136	278	(145)	(46)	770
Total assets	26,802	4,246	16,809	816	—	48,673
Total goodwill	5,025	526	877	—	—	6,428
Property additions	615	250	543	56	—	1,464

* Regulated Distribution net income for the three and nine months ended September 30, 2012, include adjustments of $21.8 million and $15.1 million, respectively, from capitalizing various construction activities of the Allegheny Utilities that were previously expensed. The effect of these adjustments was not material to the current or previous periods.

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 third quarter of 2012 were $425 million, or basic earnings of $1.02 per share of common stock ($1.01 diluted), compared with $532 million, or basic and diluted earnings of $1.27 per share of common stock in the third quarter of 2011. Earnings available to FirstEnergy Corp. in the first nine months of 2012 were $918 million, or basic earnings of $2.20 per share of common stock ($2.19 diluted), compared with $787 million, or basic earnings of $2.01 per share of common stock ($2.00 diluted) in the first nine 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 September 30		Nine Months Ended September 30	
Basic Earnings Per Share - 2011	$	1.27	$	2.01
Segment operating results[1] -				
Regulated Distribution		0.04		(0.05)
Regulated Transmission		—		—
Competitive Energy Services		(0.32)		(0.31)
Regulatory charges		(0.03)		(0.01)
Income tax charge – retiree prescription drug subsidy		(0.02)		(0.06)
Merger-related costs		—		0.37
Impact of non-core asset sales / impairments		0.02		0.08
Trust securities impairments		0.01		0.01
Mark-to-market adjustments		0.04		0.13
Merger accounting — commodity contracts		0.03		0.07
Plant closing costs		(0.04)		(0.16)
Litigation resolution		0.01		0.06
Net merger accretion[1][2]		—		0.12
Depreciation		0.02		(0.01)
Interest expense, net of amounts capitalized		0.03		0.04
Investment income		(0.01)		(0.03)
Change in effective tax rate and other tax adjustments		(0.04)		(0.08)
Other		0.01		0.02
Basic Earnings Per Share - 2012	$	1.02	$	2.20

(1) Excludes amounts that are shown separately.
(2) Includes dilutive effect of shares issued in connection with the AE merger, and three months of Allegheny results in the first three months of 2012 compared to one month during the same period of 2011.

FirstEnergy has taken a series of actions that are expected to offset the impact on its results of operations of the continued weak economy and current power price trends, including operational changes at certain power plants, staffing reductions resulting from a recently-conducted organizational study, limited hiring to fill open positions resulting from normal attrition in 2013, and employee and retiree benefit changes and cost reduction initiatives across all business units. FirstEnergy will continue to evaluate and implement these and other initiatives that are designed to improve results of operations.

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

Beginning in August 2012, FGCO changed the operating status of the 2,200 MW coal-fired W.H. Sammis power plant to cold-storage. The plant will remain available for reliability purposes when called on by PJM but is not expected to return to full operations until market conditions improve. Since this change is expected to be temporary, there are no planned layoffs and FirstEnergy tested and determined that there is no indication of an impairment to the plants' carrying cost. FirstEnergy engages in discussions with various vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

On September 19, 2012, FirstEnergy announced that it was conducting an organizational study to determine how its workforce should be aligned to best meet the challenges of the continued weak economy. The initiative included a review of corporate support departments and FES. The results of the organizational study were announced November 1, 2012, and include reductions of approximately 200 positions. In addition to the organizational study, FirstEnergy also expects further workforce reductions of approximately 300-400 occurring throughout 2013 as replacement of employees who leave the company through normal attrition will be limited. FirstEnergy did not recognize any costs in the third quarter of 2012 associated with this reorganization. FirstEnergy expects to incur approximately $10 million of severance related expenses in the fourth quarter of 2012.

Operational Matters

Operational Changes at Fossil Generation Plants

As of September 1, 2012, pursuant to plans previously announced, seven coal-fired power plants (Albright, Armstrong, Bay Shore except for generating unit 1, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island) have been deactivated while three coal-fired power plants (Ashtabula, Eastlake except for generating units 4 and 5, and Lake Shore) will remain active pursuant to RMR arrangements with PJM.

Beaver Valley Power Station to Expand Fuel Storage Capacity

On September 17, 2012, FENOC announced a plan to expand used nuclear fuel storage capacity at its two unit Beaver Valley Power Station. Under the plan, above-ground, airtight steel and concrete canisters will be installed to provide cooling, through natural air circulation, to used fuel assemblies. Initial installation will consist of six canisters and up to 47 additional canisters will be added as needed. Construction of the fuel storage system is scheduled to begin in fall 2012, with completion planned for 2014. Certain costs incurred by FirstEnergy for this project are expected to be reimbursable by the DOE under a January 2012 settlement. Due to a change in NRC regulations, FirstEnergy will be required to independently fund the radiological decommissioning of its independent spent fuel storage facilities.

Beaver Valley Unit 2 Refueling Outage

On September 24, 2012, Beaver Valley Unit 2 safely shut down for refueling, maintenance, and a turbine upgrade expected to improve efficiency and reliability. The 904 MW unit operated safely and reliably for 532 consecutive days and generated more than 12 million MWH of electricity since the completion of its last refueling in April 2011. On November 2, 2012, the plant successfully and safely completed the outage.

Hurricane Sandy Outages

In late October 2012, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Sandy. Approximately 2.3 million customers were affected by outages in New Jersey, Pennsylvania, West Virginia, Ohio and Maryland. Nearly 20,000 professionals, including employees from FirstEnergy's Utilities and outside contractors and utility workers have worked to restore service to customers who lost power following the devastating storm. As of November 7, 2012, more than 95% of customers in Pennsylvania, Ohio, West Virginia and Maryland who were affected by the storm had electric service restored. In New Jersey, where the storm damage was most severe, nearly 1.2 million customers were affected by the storm. As of November 7, 2012, 85% of affected customers in New Jersey have been restored. Storm costs are expected to exceed $500 million, of which approximately 95% is expected to be capitalized or deferred for future recovery from customers. Final storm costs will be determined during the fourth quarter of 2012.

Regulatory Matters

JCP&L Rate Case Filing

On July 31, 2012, the NJBPU ordered JCP&L to file a base rate case using a historic 2011 test year by November 1, 2012. However, due to Hurricane Sandy JCP&L requested an extension and will file a base rate case by December 1, 2012.

PUCO Approves Ohio Securitization

On October 10, 2012, the PUCO approved the application of CEI, OE and TE for a financing order to securitize previously incurred costs that are currently being recovered from customers under certain PUCO-approved deferred recovery riders, with an estimated December 31, 2012 aggregate balance of approximately $436 million as set forth in the application. If and when the transactions are executed, the proceeds are expected to be used to assist the Ohio Companies in their planned debt reductions. The Ohio Companies expect to file an application for rehearing on November 9, 2012, seeking certain changes and clarifications to the financing order necessary to complete the transaction.

CSAPR Vacated

On August 21, 2012, the U.S. Court of Appeals for the District of Columbia struck down the EPA's CSAPR, and directed the EPA to continue administering CAIR, which CSAPR was meant to replace. CSAPR would have accelerated emission reductions of SO_2 and NO_X from power plants.

PJM Removes PATH Project from Expansion Plans

On August 24, 2012, PJM officially removed the PATH project from its long-range expansion plans. Citing a slow economy for reducing the projected growth in electricity use, PJM said its updated analysis no longer indicates a need for the $2.1 billion, 275-mile transmission line to maintain grid stability. A joint venture between Allegheny and AEP, the project was suspended by PJM in February 2011. PATH expects to recover approximately $121 million of costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) over the next 5 years, of which $62 million relates to PATH-Allegheny and approximately $59 million relates to PATH-WV.

MP and PE File Generation Resource Transaction to Fulfill Energy Needs

MP and PE plan to file a Petition for Approval of a Generation Resource Transaction with the WVPSC in November 2012 that involves a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement what we believe to be a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make additional electricity and capacity purchases from the spot market which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to increase due to an increase in annual load growth of approximately 1.4%.

Ohio Companies' Alternative Energy Rider Hearing

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 were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. The PUCO has set this matter for hearing on February 19, 2013.

Financial Matters

On August 24, 2012, NGC repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $108 million. Additionally, during the third quarter of 2012, FGCO acquired certain lessor equity interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for an aggregate purchase price of approximately $95.4 million; during the fourth quarter of 2012, additional equity purchases of $37.6 million, as well as an early buyout for $23.6 million occurred.

FirstEnergy terminated $1.6 billion of forward starting interest rate swap agreements on August 16, 2012 that were executed in the second quarter of 2012, resulting in a net gain and cash proceeds of approximately $6 million. These proceeds were immediately recorded as a benefit to interest expense.

On August 21 2012, FGCO remarketed $135 million of PCRBs previously held by the company. Of the total, $106.5 million was remarketed in a four year mandatory put mode at a fixed-rate of 2.25% per annum and $28.5 million was remarketed at a fixed rate of 2.15% per annum until maturity in 2017. On September 18, 2012, FGCO and NGC also remarketed $130 million and $214 million of PCRBs, respectively, which were also previously held by the companies. Those $130 million of PCRBs were remarketed in five year mandatory put mode by FGCO at a fixed-rate of 2.50% per annum. Of the total PCRBs remarketed by NGC, $115 million were remarketed in a four year mandatory put mode at a fixed-rate of 2.20% per annum and $99 million were remarketed in a six year mandatory put mode at a fixed-rate of 2.70% per annum.

On November 1, 2012, NGC repurchased $56 million of fixed rate PCRBs that were subject to purchase on demand by the owner on that date, which it is holding for future remarketings or refinancings subject to market and other conditions.

Financial Outlook

FirstEnergy endeavors to manage its operating and capital costs in order to achieve its financial goals and commitment to shareholders. Our liquidity position remains strong, with $150 million of cash and cash equivalents and approximately $4 billion of available liquidity as of September 30, 2012. The following represent a high level summary of assumptions and drivers that management expects will impact 2013 results of operations and financial condition.

Positive earnings drivers for 2013 are expected to include:

- Higher distribution throughput for our Utilities
- Higher Ohio DCR rider revenues
- Reduced operating costs primarily as a result of staffing reductions, benefit changes, overall corporate cost reductions and fewer planned generating unit outages in 2013; and
- Reduced expenses due to the repurchase in 2012 of certain equity and other interests related to the Bruce Mansfield and Beaver-Valley 2 sale-leaseback transactions.

Negative earnings drivers for 2013 are expected to include:

- Lower margins for our competitive energy services segment from continued depressed market prices of power and lower capacity prices resulting from the PJM RPM auction beginning June 1, 2012
- Reduced transmission revenues due to lower TrAIL rate base resulting from higher accumulated deferred income taxes due to bonus depreciation in 2012; and
- Increased depreciation expense from capital projects that were placed in service in 2012.

FIRSTENERGY'S BUSINESS

During 2012, FirstEnergy completed the integration of AE into its IT business networks and financial systems. An important element of this system integration was the capability of modifying 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 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 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 Allegheny 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.

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

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment controls approximately 17,000 MWs of capacity, excluding approximately 2,700 MWs from unregulated plants recently deactivated or planned to be deactivated (see Note 9, 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 Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR, and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of September 30, 2012, the percentage of expected physical sales economically hedged was 99% for 2012 (out of 101 million MWH) and 78% for 2013 (out of 104 million MWH).

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

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. Results of operations for the nine months ended September 30, 2011, include only seven 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 12, Segment Information, to the Combined Notes to Consolidated Financial Statements. Earnings available to FirstEnergy by business segment were as follows:

	Three Months Ended September 30			Nine Months Ended September 30		
	2012	2011	Increase (Decrease)	2012	2011	Increase
	(In millions, except per share data)					
Earnings (Loss) By Business Segment:						
Regulated Distribution	$ 286	$ 280	$ 6	$ 603	$ 547	$ 56
Regulated Transmission	59	56	3	171	136	35
Competitive Energy Services	129	242	(113)	295	278	17
Other and reconciling adjustments [(1)]	(49)	(46)	(3)	(151)	(174)	23
Earnings available to FirstEnergy Corp.	$ 425	$ 532	$ (107)	$ 918	$ 787	$ 131
Basic Earnings Per Share	$ 1.02	$ 1.27	$ (0.25)	$ 2.20	$ 2.01	$ 0.19
Diluted Earnings Per Share	$ 1.01	$ 1.27	$ (0.26)	$ 2.19	$ 2.00	$ 0.19

(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.

Third Quarter 2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 2,398	$ —	$ 1,648	$ —	$ 4,046
Other	40	187	71	(33)	265
Internal	—	—	210	(210)	—
Total Revenues	2,438	187	1,929	(243)	4,311
Operating Expenses:					
Fuel	76	—	560	—	636
Purchased power	1,010	—	511	(209)	1,312
Other operating expenses	398	31	470	(43)	856
Provision for depreciation	142	27	105	8	282
Amortization of regulatory assets, net	60	1	—	—	61
General taxes	186	12	52	7	257
Total Operating Expenses	1,872	71	1,698	(237)	3,404
Operating Income	566	116	231	(6)	907
Other Income (Expense):					
Investment income	20	—	36	(17)	39
Interest expense	(135)	(23)	(73)	1	(230)
Capitalized interest	3	1	11	3	18
Total Other Expense	(112)	(22)	(26)	(13)	(173)
Income Before Income Taxes	454	94	205	(19)	734
Income taxes	168	35	76	30	309
Net Income	286	59	129	(49)	425
Income attributable to noncontrolling interest	—	—	—	—	—
Earnings Available to FirstEnergy Corp.	$ 286	$ 59	$ 129	$ (49)	$ 425

Third Quarter 2011 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 2,811	$ —	$ 1,611	$ —	$ 4,422
Other	53	181	103	(52)	285
Internal	1	—	315	(304)	12
Total Revenues	2,865	181	2,029	(356)	4,719
Operating Expenses:					
Fuel	92	—	540	—	632
Purchased power	1,294	—	362	(307)	1,349
Other operating expenses	459	28	533	(27)	993
Provision for depreciation	151	29	110	7	297
Amortization of regulatory assets, net	122	2	—	(2)	122
General taxes	198	11	55	5	269
Total Operating Expenses	2,316	70	1,600	(324)	3,662
Operating Income	549	111	429	(32)	1,057
Other Income (Expense):					
Investment income	28	—	28	(8)	48
Interest expense	(136)	(24)	(82)	(25)	(267)
Capitalized interest	3	1	9	4	17
Total Other Expense	(105)	(23)	(45)	(29)	(202)
Income Before Income Taxes	444	88	384	(61)	855
Income taxes	164	32	142	(13)	325
Net Income	280	56	242	(48)	530
Loss attributable to noncontrolling interest	—	—	—	(2)	(2)
Earnings Available to FirstEnergy Corp.	$ 280	$ 56	$ 242	$ (46)	$ 532

Changes Between Third Quarter 2012 and Third Quarter 2011 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ (413)	$ —	$ 37	$ —	$ (376)
Other	(13)	6	(32)	19	(20)
Internal	(1)	—	(105)	94	(12)
Total Revenues	(427)	6	(100)	113	(408)
Operating Expenses:					
Fuel	(16)	—	20	—	4
Purchased power	(284)	—	149	98	(37)
Other operating expenses	(61)	3	(63)	(16)	(137)
Provision for depreciation	(9)	(2)	(5)	1	(15)
Amortization (deferral) of regulatory assets, net	(62)	(1)	—	2	(61)
General taxes	(12)	1	(3)	2	(12)
Total Operating Expenses	(444)	1	98	87	(258)
Operating Income	17	5	(198)	26	(150)
Other Income (Expense):					
Investment income	(8)	—	8	(9)	(9)
Interest expense	1	1	9	26	37
Capitalized interest	—	—	2	(1)	1
Total Other Expense	(7)	1	19	16	29
Income Before Income Taxes	10	6	(179)	42	(121)
Income taxes	4	3	(66)	43	(16)
Net Income	6	3	(113)	(1)	(105)
Income attributable to noncontrolling interest	—	—	—	2	2
Earnings Available to FirstEnergy Corp.	$ 6	$ 3	$ (113)	$ (3)	$ (107)

Regulated Distribution — Third Quarter 2012 Compared with Third Quarter 2011

Net income increased by $6 million in the third quarter of 2012 compared to the same period of 2011, primarily due to reduced purchased power, lower net amortization of regulatory assets and reduced other operating expenses, partially offset by decreased revenues.

Revenues —

The $427 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Decrease
		(In millions)	
Distribution services	$ 1,121	$ 1,148	$ (27)
Generation sales:			
Retail	1,096	1,411	(315)
Wholesale	86	159	(73)
Total generation sales	1,182	1,570	(388)
Transmission	78	88	(10)
Other	57	59	(2)
Total Revenues	$ 2,438	$ 2,865	$ (427)

The decrease in distribution services revenue primarily reflected lower distribution deliveries, which decreased by 4.1% in the third 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 September 30 2012	Three Months Ended September 30 2011	Decrease
	(in thousands)		
Residential	15,008	15,571	(3.6)%
Commercial	11,436	11,824	(3.3)%
Industrial	12,385	13,103	(5.5)%
Other	146	152	(3.9)%
Total Electric Distribution MWH Deliveries	38,975	40,650	(4.1)%

Lower deliveries to residential and commercial customers reflected decreased weather-related usage resulting from a 4.3% decrease in cooling degree days, a slight reduction in the number of residential customers and declining average residential customer consumption in the third quarter of 2012 compared to the third quarter of 2011. In the industrial sector, MWH deliveries decreased by 5.5% primarily due to lower deliveries to steel customers and automotive customers resulting, in part, from the bankruptcy of a steel customer and decreased production from several facilities in the automotive sector, partially offset by increased deliveries to chemical customers.

The following table summarizes the price and volume factors contributing to the $388 million decrease in generation revenues in the third 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	$ (199)
Change in prices	(116)
	(315)
Wholesale:	
Effect of decrease in sales volumes	(35)
Change in prices	(38)
	(73)
Decrease in Generation Revenues	$ (388)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during the third quarter of 2012 compared with the same period of 2011. This increased customer shopping is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 80% from 78% for the Ohio Companies, 62% from 53% for the Pennsylvania Companies and 47% from 42% for JCP&L. The decrease in retail generation prices resulted from the impact of lower auction prices on power supply prices for the third quarter of 2012 compared to the same period of 2011.

The decrease in wholesale generation revenues of $73 million in the third quarter of 2012 resulted from the expiration and termination of NUG contracts in August 2011 and April 2012, lower capacity revenues and lower PJM market prices.

Transmission revenues decreased $10 million primarily due to lower FTR and ARR revenues in the third quarter of 2012 compared to the same period last year.

Operating Expenses —

Total operating expenses decreased by $444 million due to the following:

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

- Purchased power costs were $284 million lower in the third quarter of 2012 primarily due to increased customer shopping, which reduced purchased power requirements, and lower purchased power prices resulting from lower unit power supply costs during the third quarter of 2012 compared to the same period of 2011 as a result of lower auction prices.

Source of Change in Purchased Power	Decrease
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (108)
Change due to decreased volumes	(81)
	(189)
Purchases from FES:	
Change due to decreased unit costs	(41)
Change due to decreased volumes	(48)
	(89)
Increase in costs deferred	(6)
Net Decrease in Purchased Power Costs	$ (284)

- Transmission expenses decreased $2 million during the third quarter of 2012 compared to the same period of 2011, primarily due to lower congestion costs.

- Expenses related to storm activity decreased $30 million in the third quarter of 2012 compared to the same period in 2011.

- Other operation and maintenance expenses were lower by $41 million primarily due to a $35 million adjustment to capitalize various construction activities of the Allegheny Utilities that were previously expensed.

- Energy Efficiency program costs, which are recovered through rates, increased by $16 million.

- Depreciation expense decreased $9 million primarily due to a reduction in WP's depreciation rates authorized in September 2012 by the PPUC and retroactive to January 1, 2012.

- Net regulatory asset amortization decreased $62 million due to increased default generation service cost deferrals for ME, PN and Penn and the rate reduction for JCP&L's NUG deferred cost recovery in March of 2012, partially offset by lower storm cost deferrals in the third quarter 2012 compared to the same period last year.

- General taxes decreased by $12 million primarily due a decrease in gross receipts taxes partially offset by an increase in property taxes.

Other Expense —

Other expense increased $7 million in the third quarter of 2012 primarily due to lower investment income on OE's and TE's NDT assets and the Shippingport Capital Trust.

Regulated Transmission — Third Quarter 2012 Compared with Third Quarter 2011

Net income increased by $3 million in the third quarter of 2012 compared to the same period of 2011 primarily due to increased revenues.

Revenues —

Total revenues increased by $6 million primarily due to a higher network service peak load for the Utilities and work performed by ATSI for third-party customers.

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

Revenues by Transmission Asset Owner	**Three Months Ended September 30**		**Increase (Decrease)**
	2012	**2011**	
	(In millions)		
ATSI	$ 53	$ 50	$ 3
TrAIL	51	53	(2)
PATH	4	4	—
Utilities	79	74	5
Total Revenues	$ 187	$ 181	$ 6

Operating Expenses —

Total operating expenses increased by $1 million due to the following:

- Operation and maintenance expenses increased by $3 million primarily due to higher corporate support costs in the third quarter of 2012 compared to the same period last year.

- Depreciation expense decreased by $2 million primarily due to a reduction in WP's depreciation rates authorized in September 2012 by the PPUC and retroactive to January 1, 2012.

Other Expense —

Other expense decreased $1 million in the third quarter of 2012 due to lower net interest expense related to refinancing a transmission credit facility.

Competitive Energy Services — Third Quarter 2012 Compared with Third Quarter 2011

Net income decreased by $113 million in the third quarter of 2012, compared to the same period of 2011, due to reduced revenues and increased purchased power costs, partially offset by lower operating expenses.

Revenues —

Total revenues decreased by $100 million in the third quarter of 2012 primarily due to declines in wholesale, POLR and structured sales, partially offset by growth in direct and governmental aggregation sales. Revenues were also held down by lower unit prices compared to the third quarter of 2011.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Increase (Decrease)
		(In millions)	
Direct and Governmental Aggregation	$ 1,190	$ 1,097	$ 93
POLR and Structured Sales	327	357	(30)
Wholesale	340	460	(120)
Transmission	37	56	(19)
RECs	1	12	(11)
Other	34	47	(13)
Total Revenues	$ 1,929	$ 2,029	$ (100)

MWH Sales by Type of Service	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Increase (Decrease)
	(In thousands)		
Direct	14,312	13,088	9.4 %
Governmental Aggregation	6,768	5,195	30.3 %
POLR and Structured Sales	5,718	6,008	(4.8)%
Wholesale	6,842	7,069	(3.2)%
Total MWH Sales	33,640	31,360	7.3 %

The increase in direct and governmental aggregation revenues of $93 million resulted from the acquisition of new residential, commercial and industrial customers. This segment's customer base increased to 2.5 million customers as of September 2012, as compared to 1.7 million in September 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers.

The decrease in POLR and structured revenues of $30 million was due primarily to lower sales volumes for POLR sales to the Ohio Companies, WPP and PN due to an increased migration of customers away from default service. Revenues were also adversely impacted by lower unit prices, which were partially offset by increased structured sales. The decline in POLR sales also reflects a continued focus on other sales channels by FES.

Wholesale revenues decreased $120 million due to a $149 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. These decreases were partially offset by increased gains of $66 million on financially settled contracts and lower amortization by $12 million associated with intangible assets resulting from the merger between FirstEnergy and AE on February 25, 2011.

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	$ 177
Change in prices	(84)
	$ 93

Source of Change in POLR and Structured Revenues	Increase (Decrease)
	(In millions)
POLR and Structured:	
Effect of decrease in sales volumes	$ (17)
Change in prices	(13)
	$ (30)

Source of Change in Wholesale Revenues	Increase (Decrease)
	(In millions)
Wholesale:	
Effect of decrease in sales volumes	$ (11)
Change in prices	(38)
Gain on settled contracts	66
Commodity contract amortization	12
Capacity revenue	(149)
	$ (120)

Transmission revenues decreased by $19 million primarily due to lower congestion revenue. Revenues derived from the sale of RECs decreased $11 million in the third quarter.

Operating Expenses —

Total operating expenses increased by $98 million in the third quarter of 2012 due to the following:

- Fuel costs increased $20 million primarily due to the absence of cash received in 2011 from the assignment of a substantially below-market, long-term fossil fuel contract to a third party ($123 million), partially offset by lower volumes consumed ($78 million) and lower unit prices ($25 million). Volumes decreased as a result of the deactivation of some fossil generating units, the changes in operations at W.H. Sammis in September 2012, and an increase in economic purchases of power. Unit prices decreased due to reduced generation at higher cost units.

- Purchased power costs increased $149 million due to higher volumes ($325 million) and losses on settled contracts ($49 million), partially offset by reduced capacity expenses ($112 million) and lower unit prices ($113 million). The increase in purchased power volumes primarily relates to the overall increase in direct and governmental aggregation sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units and the change in operations at W.H. Sammis.

- Fossil operating costs decreased by $12 million due primarily to lower labor, contractor, materials and equipment costs resulting from a decrease in unplanned outages.

- Nuclear operating costs increased by $3 million due primarily to higher contractor costs, which were partially offset by lower materials and equipment costs. A refueling outage at Beaver Valley Unit 2 began late in the third quarter of 2012, while there were no nuclear outages in the third quarter of 2011.

- Transmission expenses decreased by $42 million due to lower congestion and line loss expenses ($64 million), partially offset by higher network and ancillary expenses ($22 million).

- General taxes decreased by $3 million due to lower taxes associated with a lower ownership percentage in Signal Peak and lower property taxes, partially offset by increases in revenue-related taxes.

- Depreciation expense decreased by $5 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 $12 million primarily due to favorable mark-to-market adjustments on commodity contract positions which were partially offset by the absence of revenue related to coal sales due to a lower ownership percentage in Signal Peak and the absence of impairment charges that were recognized in the third quarter of 2011.

Other Expense —

Total other expense in the third quarter of 2012 was $19 million lower than the third quarter of 2011 due to reduced net interest expense ($11 million) and higher investment income from the NDTs ($8 million).

Other — Third Quarter of 2012 Compared with Third 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 $3 million decrease in earnings available to FirstEnergy Corp. in the third quarter of 2012 compared to the same period of 2011. The decrease resulted primarily from increased income tax expense and a decrease in investment income, partially offset by lower other operating expenses as a result of reduced merger related costs and reduced interest expense primarily related to the termination of $1.6 billion of forward starting interest rate swap agreements.

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

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

First Nine Months 2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 6,727	$ —	$ 4,707	$ —	$ 11,434
Other	130	557	235	(100)	822
Internal	—	—	686	(684)	2
Total Revenues	6,857	557	5,628	(784)	12,258
Operating Expenses:					
Fuel	173	—	1,660	—	1,833
Purchased power	2,987	—	1,512	(684)	3,815
Other operating expenses	1,226	96	1,392	(132)	2,582
Provision for depreciation	439	88	307	25	859
Amortization of regulatory assets, net	197	1	—	—	198
General taxes	543	33	162	23	761
Total Operating Expenses	5,565	218	5,033	(768)	10,048
Operating Income	1,292	339	595	(16)	2,210
Other Income (Expense):					
Investment income	62	1	48	(48)	63
Interest expense	(405)	(70)	(209)	(66)	(750)
Capitalized interest	9	2	34	9	54
Total Other Expense	(334)	(67)	(127)	(105)	(633)
Income Before Income Taxes	958	272	468	(121)	1,577
Income taxes	355	101	173	29	658
Net Income	603	171	295	(150)	919
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$ 603	$ 171	$ 295	$ (151)	$ 918

First Nine Months 2011 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 7,338	$ —	$ 4,167	$ —	$ 11,505
Other	158	476	283	(123)	794
Internal	1	—	976	(921)	56
Total Revenues	7,497	476	5,426	(1,044)	12,355
Operating Expenses:					
Fuel	189	—	1,531	—	1,720
Purchased power	3,617	—	1,062	(924)	3,755
Other operating expenses	1,212	86	1,789	(36)	3,051
Provision for depreciation	409	74	307	19	809
Amortization of regulatory assets, net	337	7	—	—	344
General taxes	551	30	150	17	748
Total Operating Expenses	6,315	197	4,839	(924)	10,427
Operating Income	1,182	279	587	(120)	1,928
Other Income (Expense):					
Investment income	76	—	49	(25)	100
Interest expense	(395)	(66)	(226)	(76)	(763)
Capitalized interest	6	2	31	16	55
Total Other Expense	(313)	(64)	(146)	(85)	(608)
Income Before Income Taxes	869	215	441	(205)	1,320
Income taxes	322	79	163	(14)	550
Net Income	547	136	278	(191)	770
Loss attributable to noncontrolling interest	—	—	—	(17)	(17)
Earnings Available to FirstEnergy Corp.	$ 547	$ 136	$ 278	$ (174)	$ 787

Changes Between First Nine Months 2012 and First Nine Months 2011 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ (611)	$ —	$ 540	$ —	$ (71)
Other	(28)	81	(48)	23	28
Internal	(1)	—	(290)	237	(54)
Total Revenues	(640)	81	202	260	(97)
Operating Expenses:					
Fuel	(16)	—	129	—	113
Purchased power	(630)	—	450	240	60
Other operating expenses	14	10	(397)	(96)	(469)
Provision for depreciation	30	14	—	6	50
Amortization of regulatory assets, net	(140)	(6)	—	—	(146)
General taxes	(8)	3	12	6	13
Total Operating Expenses	(750)	21	194	156	(379)
Operating Income	110	60	8	104	282
Other Income (Expense):					
Investment income	(14)	1	(1)	(23)	(37)
Interest expense	(10)	(4)	17	10	13
Capitalized interest	3	—	3	(7)	(1)
Total Other Expense	(21)	(3)	19	(20)	(25)
Income Before Income Taxes	89	57	27	84	257
Income taxes	33	22	10	43	108
Net Income	56	35	17	41	149
Income attributable to noncontrolling interest	—	—	—	18	18
Earnings Available to FirstEnergy Corp.	$ 56	$ 35	$ 17	$ 23	$ 131

Regulated Distribution — First Nine Months of 2012 Compared to First Nine Months of 2011

Net income increased by $56 million in the first nine 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 nine months of 2012.

Results of operations for the nine months ended September 30, 2011, include only seven 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 $640 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Increase (Decrease)
		(In millions)	
Pre-merger companies:			
Distribution services	$ 2,482	$ 2,684	$ (202)
Generation sales:			
Retail	2,014	2,572	(558)
Wholesale	157	317	(160)
Total generation sales	2,171	2,889	(718)
Transmission	152	68	84
Other	124	143	(19)
Total pre-merger companies	4,929	5,784	(855)
Allegheny Utilities[(1)]	1,928	1,713	215
Total Revenues	$ 6,857	$ 7,497	$ (640)

(1) Allegheny results include 9 months in 2012 and 7 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 PPUC-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 2.4% in the first nine months of 2012 from the same period of 2011. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Increase (Decrease)
		(In thousands)	
Pre-merger companies:			
Residential	29,384	30,704	(4.3)%
Commercial	24,471	24,851	(1.5)%
Industrial	26,947	27,196	(0.9)%
Other	374	384	(2.6)%
Total pre-merger companies	81,176	83,135	(2.4)%
Allegheny Utilities[(1)]	30,326	23,648	28.2 %
Total Electric Distribution MWH Deliveries	111,502	106,783	4.4 %

(1) Allegheny results include 9 months in 2012 and 7 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 20% below 2011 levels and cooling degree days that were 1% below 2011 levels, a slight reduction in the number of residential customers and declining average residential customer consumption. In the industrial sector, MWH deliveries decreased 1%, reflecting slight decreases in deliveries to petroleum and automotive customers.

The following table summarizes the price and volume factors contributing to the $718 million decrease in generation revenues for the pre-merger companies in the first nine months 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	$ (494)
Change in prices	(64)
	(558)
Wholesale:	
Effect of decrease in sales volumes	(109)
Change in prices	(51)
	(160)
Decrease in Generation Revenues	$ (718)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories in the first nine months of 2012, compared with the same period of 2011. This increased customer shopping is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 79% from 76% for the Ohio Companies, 63% from 50% for ME's, PN's and Penn's service areas and 49% from 43% for JCP&L. The decrease in retail generation prices resulted from the impact of lower auction prices on power supply prices for the first nine months of 2012 compared to the same period of 2011.

The decrease in wholesale generation revenues of $160 million in the first nine months of 2012 resulted from the expiration and termination of NUG contracts in August 2011 and April 2012, lower capacity revenues and lower PJM market prices.

Transmission revenues increased $84 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 for the pre-merger companies decreased by $836 million due to the following:

- Purchased power costs, excluding the Allegheny Utilities, were $725 million lower in the first nine months of 2012 due primarily to a decrease in volumes required from increased customer shopping, the impact of milder weather and lower unit power supply costs during the first nine months of 2012 compared to the same period of 2011 as a result of lower auction prices.

Source of Change in Purchased Power	**Increase (Decrease)**
	(In millions)
Pre-merger companies:	
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (126)
Change due to decreased volumes	(408)
	(534)
Purchases from FES:	
Change due to decreased unit costs	(29)
Change due to decreased volumes	(211)
	(240)
Decrease in costs deferred	49
Total pre-merger companies	(725)

- Transmission expenses increased $109 million during the first nine 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.

- Other operation and maintenance expenses were lower by $60 million due primarily to lower storm related expenses in the first nine months of 2012 compared to the same period of 2011.
- Energy Efficiency program costs, which are recovered through rates, increased by $37 million.
- 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 AE merger.
- Merger-related costs decreased $57 million in the first nine months of 2012 compared to the same period of 2011.
- Depreciation expense increased by $16 million primarily due to higher asset removal costs incurred by JCP&L.
- Net regulatory asset amortization expense decreased $118 million due to the scheduled suspension of the Ohio rider recovering deferred distribution costs in December 2011 and the rate reduction for JCP&L's NUG deferred cost recovery in March of 2012, partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011 and lower storm cost deferrals.
- General taxes decreased by $25 million primarily due to a decrease in gross receipts taxes for ME, PN and JCP&L.

Operating expenses for the Allegheny Utilities are summarized in the following table:

	Nine Months Ended September 30		Increase
Operating Expenses - Allegheny[1]	**2012**	**2011**	**(Decrease)**
	(In millions)		
Purchased Power	$ 925	$ 830	$ 95
Fuel	173	188	(15)
Transmission	92	90	2
Amortization of regulatory assets, net	(38)	(16)	(22)
Other operating expenses	266	271	(5)
General taxes	101	85	16
Depreciation	115	100	15
Total Operating Expenses	$ 1,634	$ 1,548	$ 86

(1) Allegheny results include 9 months in 2012 and 7 months in 2011.

Other Allegheny operating expenses include a $24 million adjustment to capitalize various construction activities that were previously expensed.

Other Expense —

Other expense increased $21 million in the first nine months of 2012 primarily due to higher net interest expense on debt of the Allegheny Utilities and lower investment income on OE's and TE's NDT assets.

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

Net income increased by $35 million in the first nine months of 2012 compared to the same period of 2011 primarily due to two additional months of earnings in 2012 associated with TrAIL, PATH and the Allegheny Utilities' transmission assets that were acquired in the merger.

Revenues —

Total revenues increased by $81 million principally due to revenues from TrAIL, PATH and the Allegheny Utilities' transmission assets in the first nine months of 2012 compared to the same period of 2011.

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

Revenues by Transmission Asset Owner	Nine Months Ended September 30 2012	2011	Increase
		(In millions)	
ATSI	$ 161	$ 156	$ 5
TrAIL[(1)]	153	114	39
PATH[(1)]	12	9	3
Utilities[(1)]	231	197	34
Total Revenues	$ 557	$ 476	$ 81

(1) Allegheny results include 9 months in 2012 and 7 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 nine months in 2012 compared to seven 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 due to nine months of TrAIL interest expense in 2012 compared to seven months in 2011.

Competitive Energy Services — First Nine Months of 2012 Compared with First Nine Months of 2011

Net income increased by $17 million in the first nine months of 2012, compared to the same period of 2011, due to higher direct and governmental aggregation revenues and the inclusion of two additional months of earnings from the Allegheny companies in 2012, partially offset by higher operating expenses.

Results of operations for the nine months ended September 30, 2011, include only seven 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 —

Total revenues increased by $202 million in the first nine months of 2012, compared to the same period of 2011, primarily due to growth in direct and governmental aggregation sales and the inclusion of the Allegheny companies for nine months in 2012 compared to seven months in 2011. These increases were partially offset by a decline in POLR and structured sales, wholesale sales and the sale of RECs. Revenues were also adversely impacted by lower unit prices and by reduced usage by the segment's existing customer base compared to the first nine months of 2011.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30				Increase
	2012		2011		(Decrease)
			(In millions)		
Pre-merger Companies:					
Direct and Governmental Aggregation	$	3,209	$	2,836	$ 373
POLR and Structured Sales		693		799	(106)
Wholesale		251		287	(36)
Transmission		88		86	2
RECs		5		55	(50)
Other		111		130	(19)
Allegheny companies[1]		1,271		1,233	38
Total Revenues	$	5,628	$	5,426	$ 202
Allegheny companies[1]					
Direct and Governmental Aggregation	$	66	$	60	$ 6
POLR and Structured Sales		309		419	(110)
Wholesale[2]		859		687	172
Transmission		37		70	(33)
Other		—		(3)	3
Total Revenues	$	1,271	$	1,233	$ 38

(1) Allegheny results include 9 months in 2012 and 7 months in 2011.

(2) Includes $192 million in intra-segment sales by AE Supply to FES.

MWH Sales by Type of Service	Nine Months Ended September 30		Increase
	2012	2011	(Decrease)
	(In thousands)		
Pre-merger Companies:			
Direct	39,922	33,893	17.8 %
Governmental Aggregation	16,698	13,475	23.9 %
POLR and Structured Sales	12,300	12,789	(3.8)%
Wholesale	96	2,714	(96.5)%
Allegheny companies[1]	21,647	19,617	10.3 %
Total MWH Sales	90,663	82,488	9.9 %
Allegheny companies[1]			
Direct and Governmental Aggregation	1,107	983	12.6 %
POLR	5,004	5,584	(10.4)%
Structured Sales	436	1,328	(67.2)%
Wholesale	15,100	11,722	28.8 %
Total MWH Sales	21,647	19,617	10.3 %

(1) Allegheny results include 9 months in 2012 and 7 months in 2011.

The increase in direct and governmental aggregation revenues of $373 million resulted from the acquisition of new residential, commercial and industrial customers. This segment's customer base increased to 2.5 million customers as of September 2012 as compared to 1.7 million in September 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers.

The decrease in POLR and structured revenues of $106 million was due primarily to lower sales volumes to the Ohio Companies, ME, PN and other non-associated companies. Revenues were also adversely impacted by lower unit prices, which were partially offset by increased structured sales. The decline in POLR sales reflects a continued focus on other sales channels.

Wholesale revenues decreased $36 million due to a $192 million loss on an affiliated company power sales agreement between FES and AE Supply, an $84 million decrease in short-term (net hourly positions) transactions resulting primarily from reduced generation and a $48 million decrease in capacity revenues. These decreases were partially offset by increased gains of $288 million on financially settled contracts.

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	$ 559
Change in prices	(186)
	$ 373

Source of Change in POLR and Structured Revenues	**Increase (Decrease)**
	(In millions)
POLR and Structured:	
Effect of decrease in sales volumes	$ (31)
Change in prices	(75)
	$ (106)

Source of Change in Wholesale Revenues	**Increase (Decrease)**
	(In millions)
Wholesale:	
Effect of decrease in sales volumes	$ (83)
Change in prices	(1)
Gain on settled contracts	288
Loss on intra-segment settled contract	(192)
Capacity revenue	(48)
	$ (36)

Operating Expenses —

Total operating expenses for the pre-merger companies increased by $273 million in the first nine months of 2012 due to the following:

- Fuel costs increased $82 million primarily due to the absence of cash received in 2011 from the assignment of a substantially below-market, long-term fossil fuel contract to a third party ($123 million) and higher unit prices ($15 million), partially offset by lower volumes consumed ($56 million). Volumes decreased as a result of the deactivation of fossil generating units, the change in operations at W.H. Sammis in September 2012, and an increase in economic purchases of power.

- Purchased power costs increased $466 million due to higher volumes ($488 million) and losses on settled contracts ($288 million), partially offset by lower unit prices ($283 million) and reduced capacity expenses ($27 million). The increase in purchased power volumes primarily relates to the overall increase in direct and governmental aggregation sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units and the change in operations at W.H. Sammis.

- Fossil operating costs decreased by $23 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned outages.

- Nuclear operating costs decreased by $5 million due primarily to lower labor, materials and equipment costs, which were partially offset by higher contractor costs. During the first nine months of 2012, there were refueling outages at Davis

Besse, Beaver Valley Unit 1 and the start of an outage at Beaver Valley Unit 2. There were refueling outages at Perry and Beaver Valley Unit 2 during the first nine months of 2011. Total outage days were reduced slightly in the first nine months of 2012 compared to the same period of 2011.

- Transmission expenses decreased $95 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, which were partially offset by lower taxes associated with a lower ownership percentage in Signal Peak and lower property taxes.

- Depreciation expense decreased $16 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with credits resulting from a settlement with the DOE regarding storage of spent nuclear fuel.

- Other operating expenses decreased by $140 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($99 million) and the absence of 2011 expenses for a $54 million provision for excess and obsolete material relating to revised inventory practices adopted in connection with the AE merger and a $24 million impairment charge related to non-core assets. These decreases were partially offset by net increases in other expenses of $37 million associated with inter-segment leases, the absence of revenue related to coal sales due to a lower ownership percentage in Signal Peak, and labor and agent fees associated with the retail business.

The Allegheny companies' operations for nine months in 2012 and seven months in 2011 added $1,098 million and $1,177 million to operating expenses, respectively, as shown in the following table:

	Nine Months Ended September 30		Increase
Operating Expenses (Credits) - Allegheny[1]	**2012**	**2011**	**(Decrease)**
		(In millions)	
Fuel	$ 636	$ 589	$ 47
Purchased power	92	108	(16)
Fossil generation	119	118	1
Transmission	95	168	(73)
Other operating expenses	32	49	(17)
Mark-to-market adjustments	(9)	36	(45)
General taxes	40	32	8
Depreciation	93	77	16
Total Operating Expense	$ 1,098	$ 1,177	$ (79)

(1) Allegheny results include 9 months in 2012 and 7 months in 2011.

Other Expense —

Total other expense in the first nine months of 2012 decreased $19 million compared to the first nine months of 2011 due to reduced net interest expense ($20 million) from debt reductions in 2011, which was partially offset by lower investment income ($1 million) from the NDTs.

Other — First Nine Months of 2012 Compared with First Nine 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 $23 million increase in earnings available to FirstEnergy Corp. in the first nine months of 2012 compared to the same period of 2011. The increase resulted primarily from decreased other operating expenses ($96 million) due to lower merger-related costs and reduced interest expense ($10 million) primarily related to the impacts of forward starting interest rate swap agreements. These benefits were partially offset by decreased investment income ($23 million) , decreased income attributable to noncontrolling interest ($18 million) relating to Signal Peak, which was de-consolidated in the fourth quarter of 2011, and increased income tax expense ($43 million).

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 September 30, 2012 and December 31, 2011, and the changes during the nine months ended September 30, 2012:

Regulatory Assets by Source	September 30, 2012	December 31, 2011	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 294	$ 309	$ (15)
Customer receivables for future income taxes	492	519	(27)
Nuclear decommissioning and spent fuel disposal costs	(220)	(210)	(10)
Asset removal costs	(379)	(347)	(32)
Deferred transmission costs	387	340	47
Deferred generation costs	367	400	(33)
Deferred distribution costs	239	267	(28)
Contract valuations	495	299	196
Other	438	453	(15)
Total	$ 2,113	$ 2,030	$ 83

FirstEnergy had $403 million of net regulatory liabilities as of September 30, 2012, that are primarily related to asset removal costs. Regulatory assets that do not earn a current return totaled approximately $330 million as of September 30, 2012. JCP&L had $121 million of regulatory assets not earning a current return, which include storm damage costs and pension and OPEB benefits that are expected to be recovered by 2026. The remaining $209 million of regulatory assets include PJM transmission and regulatory transition costs that are expected to be recovered by 2020.

CAPITAL RESOURCES AND LIQUIDITY

As of September 30, 2012, FirstEnergy had $150 million of cash and cash equivalents and available liquidity of approximately $4.0 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 September 30, 2012, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt, which, as of September 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
Collateralized lease obligation bonds	82
Sinking fund requirements	55
Other notes	6
	$ 1,473

(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 $1.6 billion of short-term borrowings as of September 30, 2012, and no significant short-term borrowings as of December 31, 2011. FirstEnergy's available liquidity as of September 30, 2012, is summarized in the following table:

Company	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	May 2017	$ 2,000	$ 1,371
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	$ 3,869
		Cash	—	124
		Total	$ 5,550	$ 3,993

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

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $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 September 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	$ —	$ —	$ — (1)	59.0%
FES	—	1,500	—	— (2)	52.8%
AE Supply	—	1,000	—	— (2)	30.9%
FET	—	—	1,000	— (1)	63.4%
OE	500	—	—	500 (3)	61.2%
CEI	500	—	—	500 (3)	61.6%
TE	500	—	—	500 (3)	61.9%
JCP&L	425	—	—	600 (3)	44.3%
ME	300	—	—	500 (3)	54.3%
PN	300	—	—	300 (3)	57.8%
WP	200	—	—	200 (3)	49.4%
MP	150	—	—	150 (3)	55.1%
PE	150	—	—	150 (3)	53.4%
ATSI	—	—	100	100 (3)	48.5%

Penn	50	—	—	50 [3]	40.4%
TrAIL	—	—	200	400 [3]	40.5%

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

As of September 30, 2012, FE and its subsidiaries could issue additional debt of approximately $5.5 billion, or recognize a reduction in equity of approximately $3.0 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 September 30, 2012, the debt to total capitalization ratio for AGC (as defined under this credit facility) was 51.8% and AGC could issue additional debt of approximately $38 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 nine months of 2012 was 0.63% per annum for the regulated companies’ money pool and 1.31% per annum for the unregulated companies’ money pool.

Pollution Control Revenue Bonds

As of September 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 outstanding as of September 30, 2012 were issued by the following banks:

LOC Bank		**Aggregate LOC Amount**[(1)]	**LOC Termination Date**	**Reimbursements of LOC Draws Due**
		(In millions)		
UBS	$	268	April 2014	April 2014
CitiBank N.A.		164	June 2014	June 2014
Wachovia Bank		151	March 2014	March 2014
The Bank of Nova Scotia		49	April 2014	Multiple dates[(2)]
The Bank of Nova Scotia		81	April 2015	April 2015
Total	$	713		

(1) Excludes 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 September 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 $151 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 $383 million and $400 million, respectively, under provisions of their senior note indentures as of September 30, 2012. In addition, based upon their net earnings and available bondable property additions as of September 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. 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.

Based upon FGCO's net earnings and available bondable property additions under its FMB indentures as of September 30, 2012, FGCO had the capacity to issue $1.9 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 September 30, 2012, NGC had the capacity to issue $2.3 billion of additional FMBs under the terms of that indenture.

On October 10, 2012, the PUCO approved the application of CEI, OE and TE for a financing order to securitize previously incurred costs that are currently being recovered from customers under certain PUCO-approved deferred recovery riders, with an estimated December 31, 2012 aggregate balance of approximately $436 million as set forth in the application. If and when the transactions are executed, the proceeds are expected to be used to assist the Ohio Companies in their planned debt reductions. The Ohio Companies expect to file an application for rehearing on November 9, 2012, seeking certain changes and clarifications to the financing order necessary to complete the transaction.

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of September 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 September 30, 2012, FirstEnergy had $150 million of cash and cash equivalents compared to $202 million of cash and cash equivalents as of December 31, 2011. As of September 30, 2012 and December 31, 2011, FirstEnergy had approximately $55 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 by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $1,276 million during the first nine months of 2012 compared with $2,229 million being provided from operating activities during the first nine months of 2011, as summarized in the following table:

Operating Cash Flows	Nine Months Ended September 30 2012	2011	Increase (Decrease)
	(In millions)		
Net income	$ 919	$ 770	$ 149
Non-cash charges	1,498	1,796	(298)
Pension trust contributions	(600)	(375)	(225)
Working capital and other	(541)	38	(579)
	$ 1,276	$ 2,229	$ (953)

The $298 million decrease in non-cash charges and other adjustments is primarily due to the following:

- $143 million from accrued compensation and retirement benefits as a result of higher performance-related incentive compensation payments during the first nine months of 2012 compared to the same period of 2011.
- $146 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.

The $579 million decrease in cash flows from working capital and other is primarily due to the following:

- $180 million from lower collections from customers during the first nine months of 2012 primarily as a result of the effects of milder weather described in Results of Operations above.
- $125 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.
- $96 million from lower accounts payable balances as a result of the timing of payments to vendors during the first nine months of 2012 as compared to the same period of 2011.
- $150 million from increased prepaid tax balances as a result of a reduction in taxable income related to the 2011 federal tax return.

Cash Flows From Financing Activities

In the first nine months of 2012, cash provided from financing activities was $662 million compared to $2,402 million of net cash used for financing activities during the first nine months of 2011. The following tables summarize new debt financing (net of any discounts) and redemptions:

Securities Issued or Redeemed / Retired	Nine Months Ended September 30 2012	2011
	(In millions)	
New Issues		
PCRBs	$ 560	$ 272
Long-term revolving credit	—	70
FMBs	100	—
Unsecured Notes	—	261
	$ 660	$ 603
Redemptions / Retirements		
PCRBs	$ 188	$ 738
Long-term revolving credit	—	495
Senior secured notes	99	187
FMBs	—	14
Unsecured notes	583	147
	$ 870	$ 1,581

Short-term borrowings, net	$ 1,604	$ (700)

On August 21 2012, FGCO remarketed $135 million of PCRBs previously held by the company. Of the total, $106.5 million was remarketed in a four year mandatory put mode at a fixed-rate of 2.25% per annum and $28.5 million was remarketed at a fixed rate of 2.15% per annum until maturity in 2017. On September 18, 2012, FGCO and NGC also remarketed $130 million and $214 million of PCRBs, respectively, which were also previously held by the companies. Those $130 million of PCRBs were remarketed in five year mandatory put mode by FGCO at a fixed-rate of 2.50% per annum. Of the total PCRBs remarketed by NGC, $115 million were remarketed in a four year mandatory put mode at a fixed-rate of 2.20% per annum and $99 million were remarketed in a six year mandatory put mode at a fixed-rate of 2.70% per annum.

On November 1, 2012, NGC repurchased $56 million of fixed rate PCRBs that were subject to purchase on demand by the owner on that date, which it is holding for future remarketings or refinancings subject to market and other conditions.

Cash Flows From Investing Activities

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

Cash Used for (Provided from) Investing Activities	**Nine Months Ended September 30 2012**	**Nine Months Ended September 30 2011**	**Increase (Decrease)**
		(In millions)	
Property Additions:			
Regulated distribution	$ 751	$ 615	$ 136
Regulated transmission	169	250	(81)
Competitive energy services	715	543	172
Other and reconciling adjustments	51	56	(5)
Nuclear fuel	207	65	142
Cash received in AE merger	—	(590)	590
Investments	(62)	(447)	385
Other	159	63	96
	$ 1,990	$ 555	$ 1,435

Net cash used for investing activities during the first nine months of 2012 increased by $1,435 million compared to the same period of 2011. The increase was principally due to the absence in 2012 of cash acquired in the AE merger ($590 million), an increase in property additions ($222 million) and nuclear fuel ($142 million) and a decrease in proceeds from asset sales ($502 million), partially offset by a decrease in net purchases of investment securities ($68 million) and additional cash investments ($49 million).

During the remainder of 2012, capital requirements for property additions and capital leases are estimated to be approximately $852 million. FirstEnergy also expects to spend $75 million for nuclear fuel during the remainder of 2012.

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 September 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)]	$ 291
LOC (long-term debt) - interest coverage[(2)]	5
OVEC obligations	300
Other[(3)]	293
	889
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	137
LOC (long-term debt) - interest coverage[(2)]	2
FES' guarantee of NGC's nuclear property insurance	85
FES' guarantee of FGCO's sale and leaseback obligations	2,199
Other	12
	2,435
Signal Peak & Global Rail facility	350
Surety Bonds	216
LOCs[(4)]	172
	738
Total Guarantees and Other Assurances	$ 4,062

(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 $30 million for railcar leases.
(4) Includes $31 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 $33 million pledged in connection with the sale and leaseback of Perry by OE.

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, fuel, and emission 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 September 30, 2012, FES has posted collateral of $73 million. The Regulated Distribution segment has posted collateral of $21 million.

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

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3 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 table discloses the additional credit contingent contractual obligations as of September 30, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 397	$ 6	$ 42	$ 445
BB+/Ba1 Credit Ratings	$ 450	$ 6	$ 61	$ 517
Full impact of credit contingent contractual obligations	$ 671	$ 72	$ 76	$ 819

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of September 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 $40 million and $11 million, respectively.

Other Commitments and Contingencies

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

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

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility by December 31, 2013 on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, of 4% through December 31, 2012, 5% from January 1 through December 31, 2013 and, thereafter, a rate per annum equal to the then current Merrill Lynch High Yield 100 index, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to 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 $1.4 billion as of September 30, 2012, of which $109 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. In the third quarter, FGCO acquired certain lessor equity interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for an aggregate purchase price of approximately $95.4 million; during the fourth quarter of 2012, additional equity purchases of $37.6 million, as well as an early buyout for $23.6 million occurred. Additionally, FGCO is continuing the appraisal process with one remaining party and is currently involved in litigation with another party in connection with its dispute of the appraisal of the fair market value. On August 24, 2012, NGC repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $108 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 7, 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 September 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]	(39)	(49)	(44)	(35)	—	—	(167)
Prices based on models	(1)	(1)	(1)	—	(19)	(158)	(180)
Total[3]	$ (37)	$ (50)	$ (45)	$ (35)	$ (19)	$ (158)	$ (344)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and IntercontinentalExchange, Inc. quotes.
(3) Includes $(424) 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 September 30, 2012, an adverse 10% change in commodity prices would decrease net income by approximately $18 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. In August of 2012, FirstEnergy terminated forward starting swap agreements with a combined notional value of $1.6 billion, which resulted in pre-tax cash proceeds of $6 million. As a result of the swap termination, pre-tax interest expense was reduced by approximately $26 million and approximately $6 million in the three months and nine months ended September 30, 2012, respectively.

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year. A primary factor contributing to these actuarial gains and losses are changes in the discount rates used to value pension and OPEB obligations as of the measurement date of December 31 and the difference between expected and actual returns on the plans' assets. While FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 2012, based on current market indications FirstEnergy expects a pre-tax mark-to-market adjustment charge (net of amounts capitalized) to be in the range of approximately $300 million and $400 million in the aggregate.

Equity Price Risk

As of September 30, 2012, the FirstEnergy pension plan assets were in approximately 24% in equity securities, 50% in fixed income securities, 16% in absolute return strategies, 6% in real estate, 2% in private equity and 2% 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 nine months ended September 30, 2012, FirstEnergy made a voluntary pre-tax contribution to its qualified pension plans of $600 million. See Note 4, 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 September 30, 2012, approximately 58% of the funds were invested in fixed income securities, 17% of the funds were invested in equity securities and 25% 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 $1,260 million, $367 million and $533 million for fixed income securities, equity securities and short-term investments, respectively, as of September 30, 2012, excluding $43 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $37 million reduction in fair value as of September 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 September 30, 2012, no contributions were made 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 that are 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. 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 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. On December 22, 2011, the MDPSC 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.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted on September 13 and 14, 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards that the MDPSC approved on April 17, 2012, and which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. The panel's report has been referred to the MDPSC for action.

NEW JERSEY

JCP&L currently provides BGS for retail customers that do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates. The most recent BGS auction results, for supply that commenced on 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, 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. Due to Hurricane Sandy, JCP&L requested an extension and will file a base rate case using a historic 2011 test year by December 1, 2012.

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 consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. The NJBPU solicited written comments on the report from stakeholders to be submitted by September 20, 2012, and JCP&L submitted written comments on that date. The NJBPU has not specified the action that will 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. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing.

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at 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 provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in 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 RECs 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.

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. 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 by the PUCO and the subsequent appeal was dismissed by the Supreme Court of Ohio. 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. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period. Hearings were held the week of October 22, 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 were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/ performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. The PUCO has set this matter for hearing on February 19, 2013. 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. The Ohio companies are in the midst of a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks 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 EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 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. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies made a compliance filing on September 6, 2012, seeking finalization of their procurement and rate design plans, and the PPUC issued a Secretarial Letter on November 8, 2012 approving the compliance filing. The PPUC entered an order on September 27, 2012, disposing of the Petitions for Reconsideration or Clarification filed by the Pennsylvania Companies and other parties. The Pennsylvania Companies were granted an extension to file revised proposals on the retail market enhancements by November 14, 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's and PN's TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which was denied on February 28, 2012, and ME and PN also filed 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 the amended complaint on September 15, 2011, to which ME and PN responded. On September 26, 2012, United States District Court Judge Gardner entered an order dismissing the PPUC's motion to dismiss without prejudice. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. On October 9, 2012, the Supreme Court denied that petition. Accordingly, ME and PN intend to 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 could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 1, 2012, a phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. A hearing on the level of the Pennsylvania Companies' respective Phase II energy efficiency targets as established by the PPUC was held on October 19, 2012. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator.

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 SMIP,

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 AE 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 EGSs; 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. On September 27, 2012, the PPUC issued a Secretarial Letter and an "RMI End State Proposal" discussion document. PPUC staff hosted a conference call on October 17, 2012, and a Tentative Order was entered by the PPUC on November 8, 2012, seeking comments, that are due within 30 days, regarding the end state of default service and related issues.

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. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

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 February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all alternative and RECs associated with the 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 on November 22, 2011, granting ownership of all RECs produced by the facilities to MP, and holding that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility formed under PURPA owns the RECs associated with that purchase. 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 filed complaints at FERC alleging the WVPSC order violated PURPA and requested that 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 order 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, which was denied by FERC on September 20, 2012. The City of 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. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated by September 1, 2012.

The WVPSC has proceedings for each West Virginia electric utility to establish reliability targets for distribution performance. The parties entered into a settlement in September 2012 resolving all issues and establishing performance targets with more stringent targets beginning in 2014. The settlement is under review by the WVPSC.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012.

The West Virginia ENEC fuel case was filed by MP and PE at the WVPSC in August 2012 with a projected over-recovery of approximately $66 million under current rates for the next year, January 1, 2013 through December 31, 2013. MP and PE proposed no change in overall rates on January 1, 2013; however, MP and PE proposed establishing a separate regulatory liability for the difference between the recommended 2013 ENEC rates and the current ENEC rates. This estimated $66 million liability would be used to offset the rate relief MP and PE will seek in a filing later this year to become effective with the completion of a proposed generation resource transaction, which MP and PE will propose to complete by mid-2013. Discovery in the ENEC proceeding is underway and a hearing is expected in December 2012.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE plan to file a Petition for Approval of a Generation Resource Transaction with the WVPSC in November 2012 that involves a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement what we believe to be a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make additional electricity and capacity purchases from the spot market which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to increase due to an increase in annual load growth of approximately 1.4%.

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. 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.

During September 2012, RFC performed a routine compliance audit of certain parts of FirstEnergy's bulk-power systems and generally found the audited systems and processes to be in full compliance with all the audited reliability standards.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" 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 LSEs 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. FirstEnergy's request for rehearing remains pending before FERC.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays (or usage based) and 50% postage stamp (or socialization) to be effective for RTEP projects approved by the PJM Board on and after the effective date of the compliance filing. The filing is pending before FERC. Filings to demonstrate compliance with the interregional cost allocation principles of the order must be submitted to FERC by April 2013.

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. Finally, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to loads in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI is considering whether to appeal FERC's ruling on the "legacy RTEP" issue. FirstEnergy has also appealed the issue of legacy RTEP to the Seventh Circuit Court of Appeals. Although there can be no assurance, success in the appeal could terminate the ATSI zone's responsibility for legacy RTEP charges.

ATSI's filings and requests for rehearing on certain of these matters, as well as the pleadings submitted by parties that oppose ATSI's position are currently pending before FERC. Finally, on August 22, 2012, FERC approved 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.

The 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 $16 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 may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings

and appeals. These further proceedings can be divided into two classes: litigation related to the MISO's generic MVP cost allocation proposal; and litigation related to the MISO's "Schedule 39" tariff that purports to charge the MVP costs against ATSI.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of the FERC's orders that address the generic MVP tariffs 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 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 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. The hearings will start in April 2013.

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 LSEs 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. On September 10, 2012, PJM submitted the compliance filing. On October 17, 2012, FERC accepted the PJM compliance filing, resolving this matter.

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 had previously remanded one of those proceedings to FERC. In March 2010, the FERC ALJ 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 20, 2012, the California Parties appealed the FERC's decision back to the Ninth Circuit Court of Appeals. On July 19, 2012, the Ninth Circuit Court of Appeals issued an order declining to consolidate the appeal with other pending appeals regarding California refund claims, suspending briefing, and directing interested parties to intervene by August 31, 2012. AE Supply filed an intervention on August 28, 2012. On September 6, 2012, the Ninth Circuit issued an order granting AE Supply's intervention and continuing the suspension of the briefing schedule ordered on July 19, 2012. The timing of further action by the Ninth Circuit is unknown.

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, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this additional complaint. AE Supply filed a motion to dismiss this second complaint, which 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 20, 2012, the California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. In addition, on July 13, 2012, the California Attorney General requested rehearing of the June 13, 2012 order. On July 19, 2012, the Ninth Circuit consolidated the June 20, 2012 appeal with other pending appeals related to California refund claims, referred the case to the Circuit Mediator, and stayed the proceedings pending further order. On August 7, 2012, FERC rejected the California Attorney General's July 13, 2012 request for rehearing. On August 16, 2012, the California Attorney General appealed the August 7, 2012 order to the Ninth Circuit. On August 29, 2012, the Ninth Circuit consolidated the August 16, 2012 appeal with the aforementioned cases and continued the stay pending further order. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers officially canceled the project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, these companies requested authorization from FERC to recover these costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) from PJM customers over the next 5 years. Several parties have protested the request and a FERC decision is pending.

On September 20, 2012, FERC set for hearing formal challenges to the PATH formula rate annual updates submitted in June 2010 and June 2011. These challenges seek a disallowance of approximately $6.6 million in costs for the project. Settlement judge procedures are pending. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

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, which 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. FirstEnergy submitted comments on August 10, 2012, and reply comments 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.

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 vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In 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. On July 27, 2012, ME filed a motion for summary judgment on plaintiff's remaining 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. On November 1, 2012, the other defendants and the plaintiffs filed motions for summary judgment regarding various claims. FirstEnergy believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued 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 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 and their opening appellate brief is due November 14, 2012. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

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

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received 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. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities 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 December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. The Court ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. 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. 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 approximately $975 million and other changes to FirstEnergy's operations may result.

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, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. 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. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. During the nine months ended September 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) 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. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated 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. The EHB dismissed these appeals on August 29, 2012, after a settlement in the form of a Consent Decree was entered by the Commonwealth Court of Pennsylvania on August 16, 2012, resolving the disputes concerning the Hatfield's Ferry Plant NPDES permit, including elimination of the TDS limit and deferring the lower sulphate limits until July 2018.

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 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 $150 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In 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. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. On August 14, 2012, a Consent Decree was entered by the Court resolving these claims. MP is currently seeking relief from the arsenic limits through a 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 proposed Consent Decree, if entered by the court, 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 proposed Consent Decree would also require payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. The Bruce Mansfield Plant 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 FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of September 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 $123 million (including $86 million applicable to JCP&L) have been accrued through September 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 September 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 SAMA analysis. On July 26, 2012, FENOC filed a motion for Summary Disposition on the remaining admitted contention on the SAMA analysis for Davis-Besse. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the longitudinal cracking of the Davis-Besse shield building discussed below. The intervenors supplemented their petition for a contention on the shield building on multiple occasions. The ASLB scheduled

a November 5 and 6, 2012 oral argument to consider FENOC's motion for summary disposition, the intervenors request for a new contention on the Shield Building.

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. On July 9, 2012, the intervenors petitioned the ASLB for a new contention on the environmental impacts of temporary spent fuel storage by Davis-Besse due to the lack of a repository and the disposal of these wastes. 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. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

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. The NRC Staff began its 95002 inspection at the Perry plant on August 27, 2012. 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.

On September 17, 2012, FENOC announced a plan to expand used nuclear fuel storage capacity at its two unit Beaver Valley Power Station. Under the plan, above-ground, airtight steel and concrete canisters will be installed to provide cooling, through

natural air circulation, to used fuel assemblies. Initial installation will consist of six canisters and up to 47 additional canisters will be added as needed. Construction of the fuel storage system is scheduled to begin in fall 2012, with completion planned for 2014. Certain costs incurred by FirstEnergy for this project are expected to be reimbursable by the DOE under a January 2012 settlement. Due to a change in NRC regulations, FirstEnergy will be required to independently fund the radiological decommissioning of its independent spent fuel storage facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term 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, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP will file a Petition for Allowance of Appeal with the Pennsylvania Supreme Court within 30 days. A ruling by the Supreme Court on whether it will hear the case is expected in the second quarter of 2013. 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 heard arguments on the appeal in September, 2012.

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 9, 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.

Storm Cost Contingency

In late October 2012, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Sandy. Approximately 2.3 million customers were affected by outages in New Jersey, Pennsylvania, West Virginia, Ohio and Maryland. Nearly 20,000 professionals, including employees from FirstEnergy's Utilities and outside contractors and utility workers have worked to restore service to customers who lost power following the devastating storm. As of November 7, 2012, more than 95% of customers in Pennsylvania, Ohio, West Virginia and Maryland who were affected by the storm had electric service restored. In New Jersey, where the storm damage was most severe, nearly 1.2 million customers were affected by the storm. As of November 7, 2012, 85% of affected customers in New Jersey have been restored. Storm costs are expected to exceed $500 million, of which approximately 95% is expected to be capitalized or deferred for future recovery from customers. Final storm costs will be determined during the fourth quarter of 2012.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FirstEnergy. FES provides energy-related products and services to wholesale and retail customers, and through its principal subsidiaries, FGCO and NGC, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding the Allegheny facilities), and owns, through its subsidiary, NGC, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FGCO and NGC, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States.

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

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

Results of Operations

Net income increased by $28 million in the first nine months of 2012 compared to the same period of 2011, as more fully described below.

Revenues -

Total revenues increased $378 million, or 9%, in the first nine months of 2012, compared to the same period of 2011, primarily due to growth in direct and governmental aggregation sales, partially offset by a decline in POLR, structured and wholesale sales. Revenues were also adversely impacted by lower unit prices and by reduced usage by our existing customer base compared to the first nine months of 2011.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30 2012	2011	Increase (Decrease)
		(In millions)	
Direct and Governmental Aggregation	$ 3,209	$ 2,836	$ 373
POLR and Structured Sales	693	799	(106)
Wholesale	443	287	156
Transmission	88	86	2
RECs	5	55	(50)
Other	91	88	3
Total Revenues	$ 4,529	$ 4,151	$ 378

MWH Sales by Type of Service	Nine Months Ended September 30 2012	2011	Increase (Decrease)
	(In thousands)		
Direct	39,922	33,893	17.8 %
Governmental Aggregation	16,698	13,475	23.9 %
POLR and Structured Sales	12,300	12,789	(3.8)%
Wholesale	96	2,714	(96.5)%
Total MWH Sales	69,016	62,871	9.8 %

The increase in direct and governmental aggregation revenues of $373 million resulted from the acquisition of new residential, commercial and industrial customers. Sales were provided to approximately 2.5 million customers as of September 2012, compared to approximately 1.7 million as of September 2011. The volume increase was partially offset by lower unit prices for commercial, industrial and governmental aggregation customers.

The decrease in POLR and structured revenues of $106 million was due primarily to lower sales volumes to the Ohio Companies, ME, PN and other non-associated companies. Revenues were also adversely impacted by lower unit prices, which were partially offset by increased structured sales. The decline in POLR sales reflects a continued focus on other sales channels.

Wholesale revenues increased $156 million due to increased gains of $288 million on financially settled contracts, partially offset by an $84 million decrease in short-term (net hourly positions) transactions and a $48 million decrease in capacity revenues.

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	$ 559
Change in prices	(186)
	$ 373

Source of Change in POLR and Structured Revenues	Increase (Decrease)
	(In millions)
POLR and Structured:	
Effect of decrease in sales volumes	$ (31)
Change in prices	(75)
	$ (106)

Source of Change in Wholesale Revenues	Increase (Decrease)
	(In millions)
Wholesale:	
Effect of decrease in sales volumes	$ (83)
Change in prices	(1)
Gain on settled contracts	288
Capacity revenue	(48)
	$ 156

Operating Expenses -

Total operating expenses increased by $341 million in the first nine months of 2012 compared with the same period of 2011.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first nine months of 2012 compared with the same period last year:

Source of Change in Fuel and Purchased Power	Increase (Decrease)
	(In millions)
Fossil Fuel:	
Change due to increased unit costs	$ 34
Change due to volume consumed	(105)
	(71)
Nuclear Fuel:	
Change due to decreased unit costs	(1)
Change due to volume consumed	5
	4
Non-affiliated Purchased Power:	
Change due to decreased unit costs	(283)
Change due to volume purchased	488
Loss on settled contracts	288
Capacity expense	(27)
	466
Affiliated Purchased Power:	
Change due to decreased unit costs	(29)
Change due to volume purchased	29
Loss on settled contracts	192
	192
Net Increase in Fuel and Purchased Power Costs	$ 591

Fuel costs decreased $67 million primarily due to lower volumes as a result of the deactivation of fossil generating units, the change in operations at W.H. Sammis in September 2012, and an increase in economic purchases, partially offset by higher unit prices.

The increase in non-affiliated purchased power volumes primarily relates to the overall increase in sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units and the change in operations at W.H. Sammis and a $288 million loss on settled contracts. Affiliated purchased power costs increased due to a $192 million loss on an affiliated company power sales agreement between FES and AE Supply.

Other operating expenses decreased by $237 million in the first nine months of 2012, compared to the first nine months of 2011 due to the following:

- Transmission expenses decreased $95 million due primarily to lower congestion, network and line loss costs, partially offset by higher ancillary costs.
- Nuclear operating costs decreased by $5 million due primarily to lower labor, materials and equipment costs, which were partially offset by higher contractor costs. During the first nine months of 2012, there were refueling outages at Davis Besse, Beaver Valley Unit 1 and the start of an outage at Beaver Valley Unit 2. There were refueling outages at Perry and Beaver Valley Unit 2 during the first nine months of 2011. Total outage days were reduced slightly in the first nine months of 2012 compared to the same period of 2011.
- Fossil operating costs decreased by $23 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned outages.
- Other operating expenses decreased by $114 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($99 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. These decreases were partially offset by increases of $39 million for labor, agent fees, and costs associated with the retail business.

Impairment charges on long-lived assets decreased by $22 million due to 2011 charges related to peaking facilities that were subsequently sold in 2011.

General taxes increased by $13 million due to an increase in revenue-related taxes.

Depreciation expense decreased by $4 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with credits resulting from a settlement with the DOE regarding storage of spent nuclear fuel.

Other Expense -

Total other expense decreased by $21 million in the first nine months of 2012, compared to the same period of 2011, primarily due to lower net interest expense of $13 million resulting from debt reductions in 2011 and credits related to the settlement with the DOE noted above. Non-operating income increased by $8 million due primarily to additional proceeds on 2011 asset sales that were earned during the first nine months of 2012.

OHIO EDISON COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

OE is a wholly owned electric utility subsidiary of FE. OE engages in the distribution and sale of electric energy to customers in a 7,000 square mile area of central and northeastern Ohio and, through its wholly owned subsidiary, Penn, 1,100 square miles in western Pennsylvania. OE and Penn conduct business in portions of Ohio and Pennsylvania, by providing regulated electric distribution services for their customers as well as generation procurement services for customers who have not selected an alternative supplier. The areas served by OE and Penn have populations of approximately 2.3 million and 0.4 million, respectively.

For additional information with respect to OE, please see the information contained in FE's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Overview, Results of Operations - Regulatory Assets, Capital Resources and Liquidity, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Net income decreased by $11 million during the first nine months of 2012, compared to the same period of 2011, as more fully described below.

Revenues -

Revenues decreased by $19 million in the first nine months of 2012, compared with the same period of 2011, due to a decrease in retail generation revenues, partially offset by an increase in distribution revenues.

Distribution revenues increased by $4 million in the first nine months of 2012, compared to the same period of 2011, due to an increase in commercial and industrial revenue, partially offset by a decrease in residential revenue. Reduced deliveries to the residential class was driven by lower weather-related usage and declining average customer consumption. Average prices for residential customers were relatively unchanged as the implementation of Ohio's Rider NMB in June 2011, which recovers non-market based charges from PJM, including network integration transmission service charges, were offset by the suspension of Ohio's deferred cost recovery rider in December 2011. Distribution revenues for commercial and industrial customers increased in the first nine months of 2012, compared to the same period of 2011, as increased prices more than offset the slight decrease in customer usage.

Changes in distribution MWH deliveries and revenues in the first nine months of 2012, compared to the same period of 2011, are summarized in the following tables:

Distribution MWH Deliveries	Decrease
Residential	(3.7)%
Commercial	(0.4)%
Industrial	(0.2)%
Decrease in Distribution MWH Deliveries	**(1.6)%**

Distribution Revenues	Increase (Decrease)
	(In millions)
Residential	$ (8)
Commercial	6
Industrial	6
Net Increase in Distribution Revenues	**$ 4**

Retail generation revenues are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. OE and Penn defer the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings. Retail generation revenues decreased by $30 million primarily due to reduced MWH sales from increased customer shopping, partially offset by higher average prices in the residential customer class. Lower MWH sales were primarily due to lower weather-related usage resulting from heating degree days that were 20% below 2011 levels, declining average customer consumption, reduced residential accounts as well as an increase in customer shopping levels to 74% compared to 70% in the same quarter of last year. This increased customer shopping is expected to continue. Higher average prices for residential customers were primarily due to the recovery of residential generation credits for electric heating discounts, which began in September 2011.

Changes in retail generation MWH sales and revenues in the first nine months of 2012, compared to the same period of 2011, are summarized in the following tables:

Retail Generation MWH Sales	Decrease
Residential	(12.5)%
Commercial	(24.1)%
Industrial	(7.4)%
Decrease in Retail Generation Sales	**(13.5)%**

Retail Generation Revenues	Increase (Decrease)
	(In millions)
Residential	$ 22
Commercial	(36)
Industrial	(16)
Net Decrease in Retail Generation Revenues	**$ (30)**

Wholesale generation revenues increased by $4 million in the first nine months of 2012, compared to the same period of 2011, due to higher revenues from sales to NGC from OE's leasehold interests in Perry Unit 1 and Beaver Valley Unit 2.

Operating Expenses -

Total operating expenses decreased by $16 million in the first nine months of 2012, compared to the same period of 2011. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$ (80)
Other operating expenses	48
Provision for depreciation	6
Amortization of regulatory assets, net	8
General taxes	2
Net Decrease in Operating Expenses	**$ (16)**

Purchased power costs decreased in the first nine months of 2012, compared to the same period of 2011, due to lower MWH purchases resulting from reduced requirements from lower generation sales. The increase in other operating expenses for the first nine months of 2012 compared to the same period of 2011, was principally due to expenses associated with network integration transmission service charges that, prior to June 2011, were incurred by generation suppliers, and are being recovered through the Rider NMB discussed above. Amortization of regulatory assets, net, increased primarily due to lower deferred residential generation credits in 2012. Provision for depreciation expense increased mainly due to an increase in the depreciable asset base. General taxes increased due to an increase in Ohio local taxes.

Other Expenses -

Other expense increased in the first nine months of 2012, compared to the same period of 2011, mainly due to lower NDT investment income and higher interest expense.

JERSEY CENTRAL POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

JCP&L is a wholly owned, electric utility subsidiary of FE. JCP&L conducts business in New Jersey by providing regulated electric transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has an ownership interest in a hydroelectric generating facility. JCP&L procures electric supply to serve its BGS customers through a statewide auction process approved by the NJBPU.

For additional information with respect to JCP&L, please see the information contained in FE's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Overview, Results of Operations - Regulatory Assets, Capital Resources and Liquidity, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Net income decreased by $11 million in the first nine months of 2012, compared to the same period of 2011, as more fully described below.

Revenues -

Revenues decreased by $404 million, or 20%, in the first nine months of 2012, compared to the same period of 2011. The decrease in revenues was due to lower distribution, retail generation and wholesale generation revenues.

Distribution revenues decreased by $123 million in the first nine months of 2012, compared to the same period of 2011, primarily due to lower MWH deliveries and the completion of the NJBPU-approved NUG deferred cost recovery, for all customer classes. Lower MWH deliveries were principally driven by the residential and commercial classes, reflecting decreased weather-related usage in the first nine months of 2012.

Changes in distribution MWH deliveries and revenues in the first nine months of 2012 compared to the same period of 2011 are summarized in the following tables:

Distribution MWH Deliveries	**Decrease**
Residential	(4.4)%
Commercial	(3.3)%
Industrial	(2.5)%
Decrease in Distribution Deliveries	**(3.7)%**

Distribution Revenues	**Decrease**	
	(In millions)	
Residential	$	(62)
Commercial		(50)
Industrial		(11)
Decrease in Distribution Revenues	**$**	**(123)**

Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. JCP&L defers the difference between retail generation revenues and purchased power costs, resulting in no material effect on earnings. Retail generation revenues decreased by $185 million due to lower retail generation MWH sales in all customer classes primarily due to lower weather-related usage and an increase in customer shopping levels to 49% in the first nine months of 2012, compared to 43% in the same period of 2011. This increased customer shopping is expected to continue.

Decreases in retail generation MWH sales and revenues in the first nine months of 2012, compared to the same period of 2011, are summarized in the following tables:

Retail Generation MWH Sales	Decrease
Residential	(11.8)%
Commercial	(18.3)%
Industrial	(24.1)%
Decrease in Retail Generation Sales	**(13.8)%**

Retail Generation Revenues	Decrease
	(In millions)
Residential	$ (124)
Commercial	(54)
Industrial	(7)
Decrease in Retail Generation Revenues	**$ (185)**

Wholesale generation revenues decreased by $96 million in the first nine months of 2012, compared to the same period of 2011, primarily due to a decrease in PJM spot market energy sales, reflecting less volume available for sale as a result of the expiration of a NUG contract in August 2011.

Operating Expenses -

Total operating expenses decreased by $400 million in the first nine months of 2012, compared to the same period of 2011. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease)
	(In millions)
Purchased power costs	$ (278)
Other operating expenses	(33)
Provision for depreciation	8
Amortization of regulatory assets, net	(88)
General taxes	(9)
Net Decrease in Operating Expenses	**$ (400)**

Purchased power costs decreased in the first nine months of 2012 due to the expiration of a NUG contract and a decrease in volumes required, as described above. This was partially offset by the completion of the NJBPU-approved NUG deferred cost recovery, which was the primary cause for the decrease in amortization of regulatory assets, net. Depreciation expense increased mainly due to an increase in the depreciable asset base. General taxes decreased due to a phase-out of a transitional tax in New Jersey.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4. CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

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

(b) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FirstEnergy’s, FES’, OE’s and JCP&L’s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

During the quarter ended September 30, 2012, there were no material changes to the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2011.

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

(c) FirstEnergy

The table below includes information on a monthly basis regarding purchases made by FirstEnergy of its common stock during the third quarter of 2012.

	Period			
	July	August	September	Third Quarter
Total Number of Shares Purchased[1]	235,595	89,737	374,866	700,198
Average Price Paid per Share	$ 50.12	$ 47.31	$ 43.89	$ 46.42
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs	—	—	—	—
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs	—	—	—	—

(1) Share amounts reflect purchases on the open market to satisfy FirstEnergy's obligations to deliver common stock for some or all of the following: 2007 Incentive Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan, Director Compensation, Allegheny Energy, Inc., 1998 Long-Term Incentive Plan, Allegheny Energy, Inc., 2008 Long-Term Incentive Plan, Allegheny Energy, Inc., Non-Employee Director Stock Plan, Allegheny Energy, Inc., Amended and Restated Revised Plan for Deferral of Compensation of Directors, and Stock Investment Plan.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

(A)(B)	10.1	Amendment to FirstEnergy Corp. Change in Control Severance Plan, amended and restated as of September 18, 2012
(A)(B)	10.2	Amendment No. 3 to the FirstEnergy Corp. Executive Deferred Compensation Plan
(B)	12	Fixed charge ratio
(B)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(B)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(B)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended September 30, 2012, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

FES

(B)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(B)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(B)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101 *	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended September 30, 2012, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

OE

(B)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(B)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(B)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101 *	The following materials from the Quarterly Report on Form 10-Q of Ohio Edison Company. for the period ended September 30, 2012, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

JCP&L

(B)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(B)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(B)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101 *	The following materials from the Quarterly Report on Form 10-Q of Jersey Central Power & Light Company. for the period ended September 30, 2012, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

(A) Management contract or compensatory plan, contract or agreement filed pursuant to Item 601 of Regulation S-K.

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

* Users of this data are advised in accordance with Rule 406T of Regulation S-T promulgated by the SEC that this Interactive Data Files of FES, OE and JCP&L are deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

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

SIGNATURES

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

November 8, 2012

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

OHIO EDISON COMPANY
Registrant

/s/ Harvey L. Wagner

Harvey L. Wagner
Vice President, Controller
and Chief Accounting Officer

JERSEY CENTRAL POWER & LIGHT COMPANY
Registrant

/s/ Marlene A. Barwood

Marlene A. Barwood
Controller
(Principal Accounting Officer)

AMENDMENT NO. 1 TO THE
FIRSTENERGY CORP. CHANGE IN CONTROL SEVERANCE PLAN

This Amendment No. 1 (this "Amendment") to the FirstEnergy Corp. Change in Control Severance Plan (the "Plan") is hereby adopted and approved on this __ day of September, 2012, by FirstEnergy Corp., an Ohio corporation (the "Company").

Effective as of January 1, 2014, the Plan is hereby amended as follows:

1. The first sentence of Section 3.3(a) of the Plan is hereby amended by deleting the phrase "December 31, 2013" and replacing it with the phrase "December 31, 2014."

2. Paragraph (b) of Exhibit B of the Plan is hereby deleted in its entirety and replaced with the following:

   "(b) For purposes of the STIP and notwithstanding the terms of the STIP to the contrary, upon such Termination of Employment, and not later than ninety (90) days following the Termination of Employment, Executive shall be entitled to the target amount of any STIP which shall be paid in a lump sum payment. The target amount of the STIP shall be prorated in the same manner as retirement eligible employees under the STIP."

3. Paragraph (b) of Exhibit C of the Plan is hereby deleted in its entirety and replaced with the following:

   "(b) For purposes of the STIP and notwithstanding the terms of the STIP to the contrary, upon such Termination of Employment, and not later than ninety (90) days following the Termination of Employment, Executive shall be entitled to the target amount of any STIP which shall be paid in a lump sum payment. The target amount of the STIP shall be prorated in the same manner as retirement eligible employees under the STIP."

4. Capitalized terms used herein and not otherwise defined shall have the meaning ascribed to them in the Plan.

5. Except as otherwise modified in this Amendment, the Plan shall remain in full force and effect. In the event of a conflict between the terms of this Amendment and the Plan, the terms of this Amendment shall control.

[SIGNATURE ON FOLLOWING PAGE]

IN WITNESS WHEREOF, the Company, by its duly authorized officer, has executed this Amendment No. 1 to the FirstEnergy Corp. Change in Control Severance Plan on date first set forth above, effective as of January 1, 2014.

FIRSTENERGY CORP.

By: /s/ Anthony J. Alexander
Anthony J. Alexander,
President and Chief Executive
Officer of FirstEnergy Corp.

Amendment No. 3 to
FirstEnergy Corp. Executive Deferred Compensation Plan

(Effective September 28, 1985, Amended and Restated as of January 1, 2005 and Further Amended December 31, 2010 and Amended by Amendment No. 1 on April 28, 2011 and Amendment No. 2 on December 31, 2011.)

WHEREAS, FirstEnergy Corp. (the "Company"), established the FirstEnergy Corp. Executive Deferred Compensation Plan, effective September 28, 1985 as amended and restated as of January 1, 2005 and further amended December 31, 2010 and amended by Amendment No. 1 on April 28, 2011 and Amendment No. 2 on December 31, 2011 (the "Plan"); and

WHEREAS, Section 10.1 of the Plan provides that the Plan may be amended, subject to certain conditions, at any time by action of the Board of Directors of the Company (the "Board") or Compensation Committee of the Board (the "Compensation Committee") or by a writing executed on behalf of the Board or the Compensation Committee by the Company's duly elected officers; and

WHEREAS, the Board has previously delegated authority to officers of the Company to execute an amendment to the Plan; and

WHEREAS, the Company desires to amend the Plan, effective as of January 1, 2013, to allow participants to defer restricted stock units granted to them under the FirstEnergy Corp. 2007 Incentive Plan or any similar equity-based incentive plan adopted by the Company.

NOW, THEREFORE, in accordance with Section 10.1 of the Plan, the Plan is amended, effective as of January 1, 2013, as follows:

1. Section 2.18 is hereby deleted in its entirety and the remaining sections of Article 2 are hereby renumbered accordingly.

2. Section 2.21 is hereby added to Article 2 of the Plan as follows:

   "“Performance Share Award” means those earned and vested Performance Share awards granted under the FirstEnergy Corp. 2007 Incentive Plan or any similar equity-based incentive plan adopted by the Company."

3. All uses of the term "Long-Term Incentive Award" throughout the Plan are hereby changed to "Performance Share Award".

4. Section 2.9 of the Plan is hereby replaced in its entirety with the following:

   "'Deferral Election' means a commitment by a Participant to defer a portion of his or her base salary, Short-Term Incentive Award, Performance Share Award and/or Restricted Stock Unit Award pursuant to this Plan."

5. Section 2.10 of the Plan is hereby amended by adding the following paragraph at the end thereof:

   "With respect to a Restricted Stock Unit Award, "Deferral Period" shall mean the period commencing January 1 prior to the granting of the award and ending at the conclusion of the performance period for such Restricted Stock Unit Award. With respect to only a Restricted Stock Unit Award granted in 2012, the Deferral Period for such award shall mean the period commencing January 1, 2013 and ending at the conclusion of the award's performance period."

6. Section 2.13 of the Plan is hereby replaced in its entirety by the following:

   "'Elected Deferred Compensation' means the amount of base salary, Short-Term Incentive Award, Performance Share Award and Restricted Stock Unit Award that a Participant elects to defer pursuant to a Deferral Election."

7. Section 2.16 of the Plan is hereby replaced in its entirety by the following:

   "'Initial Eligible Payment Date' means, (i) with respect to a Short-Term Incentive Award or a Performance Share Award, the third (3rd) anniversary of the date on which such Short-Term Incentive Award or Performance Share Award is first credited to its respective Stock Account, and (ii) with respect to a Restricted Stock Unit Award, the date specified in the Participation Agreement applicable to the deferral of such Restricted Stock Unit Award."

8. Section 2.23 is hereby added to Article 2 of the Plan as follows:

   "'Restricted Stock Unit Award' means a Performance-Adjusted Restricted Stock Unit award granted under the FirstEnergy Corp. 2007 Incentive Plan or any similar equity-based incentive plan adopted by the Company."

9. Section 2.24 is hereby added to Article 2 of the Plan as follows:

   "'Restricted Stock Unit Account' means the Account separately established for crediting deferrals of Restricted Stock Unit Awards, pursuant to Section 4.3 of this Plan."

10. Section 3.2 of the Plan is hereby amended by adding subsection (c) thereto as follows:

"(c) Restricted Stock Unit Award. With respect to a Restricted Stock Unit Award granted in 2013 and thereafter, a participant may elect to defer a percentage of his or her Restricted Stock Unit Award that is earned during its respective Deferral Period and otherwise payable, if at all, at the conclusion of its respective vesting period. The amount deferred must be stated as a whole percentage and shall not be more than one hundred percent (100%) of such award, less any taxes or other amounts that may be required to be withheld.

Solely with respect to a Restricted Stock Unit Award that is granted in 2012, a participant may elect to defer a percentage of such Restricted Stock Unit Award that is earned during its respective Deferral Period and otherwise payable, if at all, at the conclusion of the vesting period for the award; provided, however, that the only eligible portion for deferral of such award is the portion of the award that is paid subject to the achievement of performance factors. Any portion of a Restricted Stock Unit Award granted in 2012 that is earned only upon the satisfaction of service requirements shall not be eligible for deferral. The amount deferred for any Restricted Stock Unit Award granted in 2012 must be stated as a whole percentage and will apply only to the portion of such Restricted Stock Unit Award that is subject to the achievement of performance factors, less any taxes or other amounts that may be required to be withheld."

11. Article 4 of the Plan is hereby replaced in its entirety with the following:

"4.1 Elected Deferred Compensation

A Participant's Elected Deferred Compensation shall be credited to the Participant's Account as of the date such amount would have otherwise been paid to such Participant.

4.2 Retirement Account

(a) Establishing a Retirement Account. A Participant may establish an annual Retirement Account on and after January 1, 2005 which shall be maintained solely for recordkeeping purposes, by making a Deferral Election.

(b) Maximum Deferral. A Participant may elect to defer up to fifty percent (50%) of base salary and up to one hundred percent (100%) of the Short-Term Incentive Award into the Retirement Account.

(c) Earnings

(i) Any amounts credited to a Retirement Account prior to January 1, 2013 shall be credited with earnings equal to the Interest Rate plus three (3) percentage points. Effective January 1, 2013, any amounts credited to a Retirement Account that is established after December 31, 2012 shall be credited with earnings equal to the Interest Rate plus one (1) percentage point. The maximum Interest Rate shall be twelve percent (12%).

(ii) Commencing January 1, 2008, the Company may, in its sole discretion, permit Participants to elect from among a series of hypothetical investment options, including the option described in paragraph (i) above, which are selected by the Administrative Committee and to which the Participants' Elected Deferred Compensation shall be credited. If the Company permits investment option elections by Participants, the Participants' Accounts shall be credited daily with earnings, gains and losses as if such Accounts were invested in one (1) or more Plan investment options, as selected by the Participants. Investment options may be changed or provided from time to time by the Administrative Committee in its sole discretion.

(iii) Participants may change the options into which Elected Deferred Compensation is credited and may change the allocation of existing Account balances which elections shall become effective as of the first (1st) day of the month following the date such election is submitted to the Administrative Committee.

(d) Earnings for Senior Management Retirees. The Retirement Account of any Member of senior management who retired before July 1, 1998 shall be credited with the greater of:

(i) The Interest Rate plus four (4) percentage points, or

(ii) The equivalent of a twelve percent (12%) annual yield.

4.3 Stock Account and Restricted Stock Unit Account

(a) Establishing a Stock Account. A Participant may establish an annual Stock Account, which shall be maintained solely for recordkeeping purposes, by making a Deferral Election. A separate Restricted Stock Unit Account shall be maintained for deferrals credited with respect to Restricted Stock Unit Awards.

(b) Maximum Deferral. A Participant may elect to defer up to one hundred percent (100%) of the Short-Term Incentive Award and Performance Share Award into the Stock Account. A Participant may also elect to defer up to one hundred percent (100%) of the Restricted Stock Units Award into the Restricted Stock Unit Account; provided that, with respect to a Restricted Stock Unit Award granted in 2012, a participant may defer into the Restricted Stock Unit Account only the portion of such award that is subject to the achievement of performance factors.

(c) Stock Premium. With respect to deferrals of any Short-Term Incentive Award and/or Performance Share Award that is earned during a Deferral Period that ends prior to January 1, 2011 and that otherwise would have been payable no later than December 31, 2011, amounts deferred into the Stock Account shall be credited with an amount equal to twenty percent (20%) of the amount deferred into the Stock Account. Such premium shall be credited as of the date the corresponding Elected Deferred Compensation is credited to the Stock Account.

(d) Stock Units and Earnings. Amounts deferred into the Stock Account shall be converted into units of Company common stock. The number of stock units credited to the Stock Account shall be determined by dividing the amount deferred into the Stock Account, plus, with respect to deferrals of any Short-Term Incentive Award and/or Performance Share Award that is earned during a Deferral Period that ends prior to January 1, 2011 and that otherwise would have been payable no later than December 31, 2011, the Stock Premium described in (c) above, by the average daily closing price of Company common stock during February of the Deferral Period in which the Elected Deferred Compensation is credited to the Account.

Amounts deferred into the Restricted Stock Unit Account shall be units of the Company's common stock. The number of stock units credited to the Restricted Stock Unit Account shall be determined by the number of whole and fractional shares, rounded up to the nearest whole share, which a Participant has elected to defer as calculated at the time of vesting of the Restricted Stock Unit Award.

(e) Dividends. Additional stock units shall be credited to each Stock Account and Restricted Stock Unit Account at the time dividend payments are made to Company shareholders. The number of additional units credited shall be based on the number of units in the Stock Account and Restricted Stock Unit Account, the dividend rate and the market price of Company stock at the close of that business day.

(f) Automatic Cessation of Stock Premium and Dividends.

(i) Unless the Plan is terminated by the Company prior to the following, the crediting of the 20% stock premium in Company common stock will automatically cease on January 1, 2011 with respect to deferrals of any Short-Term Incentive Award and/or Performance Share Award that is earned during a Deferral Period that commences on or after January 1, 2011 and that otherwise would have been payable later than December 31, 2011, or earlier if the maximum share reserve of 1,000,000 shares is reached.

(ii) Unless the Plan is terminated by the Company prior to the following, the crediting of the dividends under Section 4.3(e) in Company common stock will automatically cease on May 17, 2014 or earlier if the maximum share reserve of 1,000,000 shares is reached, unless shareholders reapprove this feature on the earlier of the prior date or prior to the depletion of the maximum share reserve.

4.4 Retirement Stock Account

(a) Establishing a Retirement Stock Account. Effective January 1, 2002, a Retirement Stock Account may be established for a Participant who has elected to defer receipt of his or her Stock Account pursuant to Section 5.5(a) of this Plan solely for recordkeeping purposes and shall be credited with earnings, gains, losses and dividends in the same manner as the Stock Account.

(b) Transfer to Retirement Account. Upon Separation from Service or death the value of the Participant's Retirement Stock Account shall be transferred to the Participant's Retirement Account as of the date of Separation from Service or death and paid in cash pursuant to Article 5 of this Plan.

4.5 Deferred Compensation Benefit

The aggregate balances of a Participant's Retirement Account, Stock Account, Restricted Stock Unit Account and Retirement Stock Account shall be the Participant's "Deferred Compensation Benefit."

4.6 Amounts Transferred from the GPU Companies Deferred Compensation Plan and Nonqualified Pension Plan

(a) Deferred Compensation Amounts. As of November 7, 2001, certain account balances from the GPU Companies Deferred Compensation Plan were transferred to this Plan in conjunction with the merger of GPU, Inc. into the Company. As of such date, the transferred balances shall be credited in a Retirement Account for each such former employee of the GPU Companies and shall be credited with earnings in the same manner as all other Retirement Accounts.

(b) Nonqualified Pension Plan Amounts. As of November 7, 2001, the accrued benefit associated with certain GPU nonqualified pension plans were transferred to this Plan in conjunction with the merger of GPU, Inc. into the Company. Each such former employee affected by this transfer shall be entitled to receive an increase in such employee's benefit equal to ten percent (10%) of the benefit, so that, when benefits are paid, they will be ten percent (10%) greater than the amount that otherwise would have been paid had the benefit been paid under the GPU Companies nonqualified pension plans.

4.7 Vesting of Accounts

Each Participant shall be vested in the amounts credited to such Participant's Accounts as follows:

(a) Elected Deferred Compensation. A Participant shall be one hundred percent (100%) vested at all times in his Elected Deferred Compensation and any gains or losses thereon regardless of the Account to which such amounts are credited.

(b) Stock Premium. A Stock Premium, and any earnings gains or losses thereon shall be one hundred percent (100%) vested on:

(i) the Initial Eligible Payment Date for the related Elected Deferred Compensation, provided the Participant is either:

a) Employed by an Employer on the Initial Eligible Payment Date, or

b) Has a Separation from Service on or after reaching age sixty (60);

(ii) the death of the Participant;

(iii) a Separation from Service of the Participant due to one (1) of the following events:

a) his or her Disability;

b) involuntary termination under conditions where the Participant becomes eligible for and elects to accept an Employer severance benefit; or

(iv) a Change in Control.

4.8 Statement of Accounts

The Administrative Committee shall submit to each Participant, after the close of each calendar year and at such other times as determined by the Administrative Committee, a statement setting forth the balance to the credit of the Accounts maintained for a Participant."

12. Sections 5.1, 5.2, 5.3 and 5.4 are hereby amended by adding the phrase "Restricted Stock Unit Account" after each instance of the phrase "Stock Account" therein and "Restricted Stock Unit Accounts" after each instance of the phrase "Stock Accounts" therein.

13. Section 5.5 is hereby amended by adding subsections (d) and (e) to the end thereof:

"(d) Benefits payable from Restricted Stock Unit Accounts. With respect to any Restricted Stock Unit Account, unless a Participant elects otherwise pursuant to this Section 5.5(d) or Section 5.5(e), a Participant who is employed by any Employer on the respective Initial Eligible Payment Date for such Restricted Stock Unit Account shall receive a Deferred Compensation Benefit equal to the amount of such Restricted Stock Unit Account in Company common stock upon the Initial Eligible Payment Date. Notwithstanding the foregoing, if a Participant's Separation from Service or death occurs prior to the respective Initial Eligible Payment Date, the balance of the Restricted Stock Unit Account shall be transferred to the Retirement Account for the applicable Deferral Period and paid in accordance with the elections made for such Retirement Account in the applicable Participant Agreement or, if applicable, under the provisions of the Plan.

A Participant may elect in the Participation Agreement applicable to a Restricted Stock Unit Account to receive a distribution of such Restricted Stock Unit Account upon his or her Separation from Service or death. If such an election is made, the balance of such Restricted Stock Unit Account shall be credited to the Restricted Stock Unit Account until the Participant's Separation from Service or death and then transferred to the Retirement Account established for the applicable Deferral Period and paid in cash pursuant to the Participant's election with respect to such Retirement Account or the relevant Plan provisions, whichever is applicable, under Sections 5.1, 5.2, 5.3, or 5.5 of this Plan.

(e) Changing Date or Form of Payment. Subject to the Administrative Committee's discretion and solely with respect to Restricted Stock Unit Account balances, including deemed earnings, gains and losses credited thereon, a Participant may amend his or her elections regarding the timing of the payment in a manner that is consistent with the requirements of Treasury Regulation § 1.409A-2(b), provided:

(i) such election is submitted to the Committee in writing at least twelve (12) months prior to the date any amount is to be distributed from the Plan; and

(ii) such election shall not take effect until twelve (12) months after it is submitted to the Committee in writing; and

(iii) the payment of the benefits shall not commence until at least five (5) years from the date such payment would otherwise have been made."

14. Section 5.7(d) is hereby amended by adding the phrase "Restricted Stock Unit Account" after the phrase "Stock Account."

15. Capitalized terms used herein and not otherwise defined shall have the meaning ascribed to them in the Plan.

16. Except as otherwise modified in this Amendment, the Plan shall remain in full force and effect. In the event of a conflict between the terms of this Amendment and the Plan, the terms of this Amendment shall control.

IN WITNESS WHEREOF, the Board of Directors of FirstEnergy Corp., has caused this Amendment No. 3 to FirstEnergy Corp. Executive Deferred Compensation Plan to be executed on this 7th day of November, 2012, effective as of the date set forth above.

FIRSTENERGY CORP.

By: /s/ Anthony J. Alexander

Anthony J. Alexander,
President and Chief Executive Officer of FirstEnergy Corp.

EXHIBIT 12

FIRSTENERGY CORP.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30	
	2012	2011
	(Dollars in millions)	
EARNINGS AS DEFINED IN REGULATION S-K:		
Income before extraordinary items	$ 919	$ 770
Interest and other charges, before reduction for amounts capitalized and deferred	750	763
Provision for income taxes	658	550
Interest element of rentals charged to income (1)	105	114
Earnings as defined	$ 2,432	$ 2,197
FIXED CHARGES AS DEFINED IN REGULATION S-K:		
Interest before reduction for amounts capitalized and deferred	$ 750	$ 763
Interest element of rentals charged to income (1)	105	114
Fixed charges as defined	$ 855	$ 877
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.84	2.51

(1) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

EXHIBIT 31.1

Certification

I, Anthony J. Alexander, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Anthony J. Alexander

Anthony J. Alexander

Chief Executive Officer

Certification

I, Donald R. Schneider, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Solutions Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Donald R. Schneider

Donald R. Schneider

Chief Executive Officer

EXHIBIT 31.1

Certification

I, Charles E. Jones, certify that:

1. I have reviewed this report on Form 10-Q of Ohio Edison Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Charles E. Jones
Charles E. Jones
Chief Executive Officer

EXHIBIT 31.1

Certification

I, Donald M. Lynch, certify that:

1. I have reviewed this report on Form 10-Q of Jersey Central Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Donald M. Lynch

Donald M. Lynch
Chief Executive Officer

EXHIBIT 31.2

Certification

I, Mark T. Clark, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Mark T. Clark

Mark T. Clark

Chief Financial Officer

EXHIBIT 31.2

Certification

I, Mark T. Clark, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Solutions Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Mark T. Clark

Mark T. Clark

Chief Financial Officer

EXHIBIT 31.2

Certification

I, Mark T. Clark, certify that:

1. I have reviewed this report on Form 10-Q of Ohio Edison Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Mark T. Clark

Mark T. Clark

Chief Financial Officer

EXHIBIT 31.2

Certification

I, Marlene A. Barwood, certify that:

1. I have reviewed this report on Form 10-Q of Jersey Central Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2012

/s/ Marlene A. Barwood

Marlene A. Barwood

Chief Financial Officer

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Corp. (“Company”) on Form 10-Q for the period ending September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Anthony J. Alexander

Anthony J. Alexander
Chief Executive Officer

/s/ Mark T. Clark

Mark T. Clark
Chief Financial Officer

Date: November 8, 2012

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Solutions Corp. (“Company”) on Form 10-Q for the period ending September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Donald R. Schneider
Donald R. Schneider
President
(Chief Executive Officer)

/s/ Mark T. Clark
Mark T. Clark
Chief Financial Officer

Date: November 8, 2012

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of Ohio Edison Company ("Company") on Form 10-Q for the period ending September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles E. Jones
Charles E. Jones
President
(Chief Executive Officer)

/s/ Mark T. Clark
Mark T. Clark
Chief Financial Officer

Date: November 8, 2012

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of Jersey Central Power & Light Company ("Company") on Form 10-Q for the period ending September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his or her knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Donald M. Lynch

Donald M. Lynch
President
(Chief Executive Officer)

/s/ Marlene A. Barwood

Marlene A. Barwood
Controller
(Chief Financial Officer)

Date: November 8, 2012

Supplemental Guarantor Information (Tables)	9 Months Ended Sep. 30, 2012
Supplemental Guarantor Information [Abstract]	
Condensed Consolidating Statements of Income and Comprehensive Income	

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$1,523	$ 617	$ 395	$ (978)	$ 1,557
OPERATING EXPENSES:					
Fuel	—	248	55	—	303
Purchased power from affiliates	1,042	—	67	(978)	131
Purchased power from non-affiliates	499	—	—	—	499
Other operating expenses	130	79	122	12	343
Provision for depreciation	1	30	41	(1)	71
General taxes	20	10	5	—	35
Total operating expenses	1,692	367	290	(967)	1,382
OPERATING INCOME (LOSS)	(169)	250	105	(11)	175
OTHER INCOME (EXPENSE):					
Investment income	1	5	37	(5)	38
Miscellaneous income, including net income from equity investees	317	—	—	(316)	1
Interest expense — affiliates	(5)	(2)	(1)	5	(3)
Interest expense — other	(25)	(27)	(15)	16	(51)
Capitalized interest	—	1	8	—	9
Total other income (expense)	288	(23)	29	(300)	(6)

INCOME BEFORE INCOME TAXES	119	227	134	(311)	169
INCOME TAXES (BENEFITS)	18	(11)	59	2	68
NET INCOME	$ 101	$ 238	$ 75	$ (313)	$ 101
<u>STATEMENTS OF COMPREHENSIVE INCOME</u>					
NET INCOME	$ 101	$ 238	$ 75	$ (313)	$ 101
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available for sale securities	(2)	—	(1)	1	(2)
Other comprehensive loss	(9)	(4)	(1)	5	(9)
Income tax benefits on other comprehensive loss	(3)	(2)	—	2	(3)
Other comprehensive loss, net of tax	(6)	(2)	(1)	3	(6)
COMPREHENSIVE INCOME	$ 95	$ 236	$ 74	$ (310)	$ 95

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
<u>STATEMENTS OF INCOME</u>					
REVENUES	$4,443	$1,795	$1,262	$ (2,971)	$ 4,529

OPERATING EXPENSES:					
Fuel	—	824	154	—	978
Purchased power from affiliates	3,163	—	189	(2,971)	381
Purchased power from non-affiliates	1,420	—	—	—	1,420
Other operating expenses	313	271	410	37	1,031
Provision for depreciation	3	90	114	(4)	203
General taxes	60	28	16	—	104
Total operating expenses	4,959	1,213	883	(2,938)	4,117
OPERATING INCOME (LOSS)	(516)	582	379	(33)	412
OTHER INCOME (EXPENSE):					
Investment income	2	14	49	(15)	50
Miscellaneous income, including net income from equity investees	854	19	—	(848)	25
Interest expense — affiliates	(14)	(5)	(3)	15	(7)
Interest expense — other	(72)	(79)	(36)	47	(140)
Capitalized interest	—	3	24	—	27
Total other income (expense)	770	(48)	34	(801)	(45)
INCOME BEFORE INCOME TAXES	254	534	413	(834)	367
INCOME TAXES (BENEFITS)	32	(19)	124	8	145
NET INCOME	$ 222	$ 553	$ 289	$ (842)	$ 222
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 222	$ 553	$ 289	$ (842)	$ 222

OTHER COMPREHENSIVE INCOME					
Pensions and OPEB prior service costs	(2)	(1)	—	1	(2)
Amortized loss on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available for sale securities	11	—	12	(12)	11
Other comprehensive income (loss)	3	(1)	12	(11)	3
Income taxes (benefits) on other comprehensive income (loss)	1	(1)	5	(4)	1
Other comprehensive income, net of tax	2	—	7	(7)	2
COMPREHENSIVE INCOME	$ 224	$ 553	$ 296	$ (849)	$ 224

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$1,445	$ 686	$ 371	$ (1,035)	$ 1,467
OPERATING EXPENSES:					
Fuel	6	323	57	—	386
Purchased power from affiliates	1,031	4	55	(1,035)	55
Purchased power from non-affiliates	330	(2)	—	—	328
Other operating expenses	162	94	122	12	390
Provision for depreciation	1	33	36	(1)	69
General taxes	19	9	3	—	31
Impairment of long-lived assets	—	2	—	—	2

Total operating expenses	1,549	463	273	(1,024)	1,261
OPERATING INCOME (LOSS)	(104)	223	98	(11)	206
OTHER INCOME (EXPENSE):					
Investment income	—	—	28	—	28
Miscellaneous income, including net income from equity investees	196	16	—	(203)	9
Interest expense — affiliates	—	(1)	(1)	—	(2)
Interest expense — other	(24)	(26)	(16)	15	(51)
Capitalized interest	—	3	5	—	8
Total other income (expense)	172	(8)	16	(188)	(8)
INCOME BEFORE INCOME TAXES	68	215	114	(199)	198
INCOME TAXES (BENEFITS)	(52)	83	45	2	78
NET INCOME	$ 120	$ 132	$ 69	$ (201)	$ 120
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 120	$ 132	$ 69	$ (201)	$ 120
OTHER COMPREHENSIVE LOSS					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available for sale securities	(22)	—	(22)	22	(22)
Other comprehensive loss	(28)	(4)	(22)	26	(28)
Income tax benefits on other	(11)	(2)	(9)	11	(11)

comprehensive loss					
Other comprehensive loss, net of tax	(17)	(2)	(13)	15	(17)
COMPREHENSIVE INCOME	$ 103	$ 130	$ 56	$ (186)	$ 103

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Nine Months Ended September 30, 2011	**FES**	**FGCO**	**NGC**	**Eliminations**	**Consolidated**
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$4,087	$1,964	$1,233	$ (3,133)	$ 4,151
OPERATING EXPENSES:					
Fuel	13	883	149	—	1,045
Purchased power from affiliates	3,118	15	189	(3,133)	189
Purchased power from non-affiliates	959	(5)	—	—	954
Other operating expenses	483	313	435	37	1,268
Provision for depreciation	3	96	112	(4)	207
General taxes	46	28	17	—	91
Impairment of long-lived assets	—	22	—	—	22
Total operating expenses	4,622	1,352	902	(3,100)	3,776
OPERATING INCOME (LOSS)	(535)	612	331	(33)	375
OTHER INCOME (EXPENSE):					
Investment income	1	1	48	—	50
Miscellaneous income, including net income from equity investees	570	18	—	(571)	17
Interest expense — affiliates	(1)	(2)	(2)	—	(5)

Interest expense — other	(72)	(82)	(49)	47	(156)
Capitalized interest	—	13	15	—	28
Total other income (expense)	498	(52)	12	(524)	(66)
INCOME (LOSS) BEFORE INCOME TAXES	(37)	560	343	(557)	309
INCOME TAXES (BENEFITS)	(231)	208	131	7	115
NET INCOME	$ 194	$ 352	$ 212	$ (564)	$ 194
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 194	$ 352	$ 212	$ (564)	$ 194
OTHER COMPREHENSIVE LOSS					
Pensions and OPEB prior service costs	(14)	(12)	—	12	(14)
Amortized gain on derivative hedges	4	—	—	—	4
Change in unrealized gain on available for sale securities	(7)	—	(7)	7	(7)
Other comprehensive loss	(17)	(12)	(7)	19	(17)
Income tax benefits on other comprehensive loss	(7)	(6)	(3)	9	(7)
Other comprehensive loss, net of tax	(10)	(6)	(4)	10	(10)
COMPREHENSIVE INCOME	$ 184	$ 346	$ 208	$ (554)	$ 184

Condensed Consolidating Balance Sheets

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		

ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 3	$ —	$ —	$ 3
Receivables-					
Customers	485	—	—	—	485
Affiliated companies	362	410	238	(608)	402
Other	63	15	25	—	103
Notes receivable from affiliated companies	153	2,061	406	(2,182)	438
Materials and supplies, at average cost	66	257	210	—	533
Derivatives	209	—	—	—	209
Prepayments and other	85	24	27	1	137
	1,423	2,770	906	(2,789)	2,310
PROPERTY, PLANT AND EQUIPMENT:					
In service	89	5,730	6,204	(385)	11,638
Less — Accumulated provision for depreciation	31	1,888	2,578	(185)	4,312
	58	3,842	3,626	(200)	7,326
Construction work in progress	32	203	820	—	1,055
	90	4,045	4,446	(200)	8,381
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,286	—	1,286
Investment in affiliated companies	6,555	—	—	(6,555)	—
Other	5	11	—	—	16
	6,560	11	1,286	(6,555)	1,302
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	270	—	(270)	—
Customer intangibles	114	—	—	—	114
Goodwill	24	—	—	—	24
Property taxes	—	20	23	—	43
Unamortized sale and leaseback costs	—	—	—	111	111
Derivatives	78	—	—	—	78
Other	127	163	2	(111)	181
	343	453	25	(270)	551
	$ 8,416	$ 7,279	$ 6,663	$ (9,814)	$ 12,544
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 565	$ 529	$ (21)	$ 1,074
Short-term borrowings-					
Affiliated companies	2,048	135	—	(2,183)	—
Accounts payable-					

Affiliated companies	618	311	463	(605)	787
Other	82	92	—	—	174
Accrued taxes	49	19	19	(4)	83
Derivatives	153	—	—	—	153
Other	50	154	24	16	244
	3,001	1,276	1,035	(2,797)	2,515
CAPITALIZATION:					
Total equity	3,802	3,651	2,886	(6,537)	3,802
Long-term debt and other long-term obligations	1,482	1,976	845	(1,218)	3,085
	5,284	5,627	3,731	(7,755)	6,887
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	900	900
Accumulated deferred income taxes	39	—	624	(162)	501
Asset retirement obligations	—	29	921	—	950
Retirement benefits	35	148	—	—	183
Lease market valuation liability	—	87	—	—	87
Other	57	112	352	—	521
	131	376	1,897	738	3,142
	$ 8,416	$ 7,279	$ 6,663	$ (9,814)	$ 12,544

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

Condensed Consolidating Statements of Cash Flows

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (Unaudited)

For the Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(971)	$ 683	$ 799	$ (10)	$ 501
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	317	243	—	560
Short-term borrowings, net	982	49	—	(1,028)	3
Redemptions and Repayments-					
Long-term debt	—	(169)	(87)	10	(246)
Short-term borrowings, net	—	—	(32)	32	—
Other	(1)	(6)	(2)	—	(9)
Net cash provided from financing activities	981	191	122	(986)	308
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(10)	(175)	(350)	—	(535)
Nuclear fuel	—	—	(207)	—	(207)
Proceeds from asset sales	—	17	—	—	17
Sales of investment securities held in trusts	—	—	1,167	—	1,167
Purchases of investment securities held in trusts	—	—	(1,194)	—	(1,194)
Loans to affiliated companies, net	1	(715)	(337)	996	(55)
Other	(1)	(5)	—	—	(6)
Net cash used for investing activities	(10)	(878)	(921)	996	(813)

Net change in cash and cash equivalents	—	(4)	—	—	(4)
Cash and cash equivalents at beginning of period	—	7	—	—	7
Cash and cash equivalents at end of period	$ —	$ 3	$ —	$ —	$ 3

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (Unaudited)

For the Nine Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(367)	$ 539	$ 374	$ (9)	$ 537
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	140	107	—	247
Short-term borrowings, net	750	59	25	(834)	—
Redemptions and Repayments-					
Long-term debt	(136)	(351)	(313)	9	(791)
Short-term borrowings, net	—	—	—	(12)	(12)
Other	(8)	(1)	(2)	1	(10)
Net cash provided from (used for) financing activities	606	(153)	(183)	(836)	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8)	(143)	(257)	—	(408)
Nuclear fuel	—	—	(65)	—	(65)
Proceeds from asset sales	9	510	—	—	519
Sales of investment securities held in trusts	—	—	1,613	—	1,613

Purchases of investment securities held in trusts	—	—	(1,654)	—	(1,654)
Loans to affiliated companies, net	(228)	(732)	172	845	57
Other	(12)	(24)	—	—	(36)
Net cash used for investing activities	(239)	(389)	(191)	845	26
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

Fair Value Measurements (Details 4) (USD $) In Millions, unless otherwise specified	**3 Months Ended**		**9 Months Ended**	
	Sep. 30, 2012	**Sep. 30, 2011**	**Sep. 30, 2012**	**Sep. 30, 2011**
Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income				
Sales Proceeds	$ 1,751	$ 1,974	$ 2,133	$ 3,678
Realized gains	81	98	118	220
Realized losses	(32)	(38)	(67)	(83)
Interest and dividend income	18	20	51	72
FES				
Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income				
Sales Proceeds	1,059	1,100	1,167	1,613
Realized gains	60	52	85	74
Realized losses	(23)	(19)	(48)	(42)
Interest and dividend income	10	9	27	41
OE				
Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income				
Sales Proceeds	0	134	57	154
Realized gains	0	7	0	7
Realized losses	0	(1)	0	(1)
Interest and dividend income	1	1	2	3
JCP&L				
Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income				
Sales Proceeds	211	234	376	610
Realized gains	6	11	8	37
Realized losses	(2)	(4)	(4)	(10)
Interest and dividend income	$ 4	$ 5	$ 11	$ 13

Variable Interest Entities (Details) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	
FES		
Net exposure to loss based upon the casualty value provisions		
Maximum Exposure	$ 1,339	
Discounted Lease Payments, net	1,123	[1]
Variable Interest Entities Net Exposure	216	
OE		
Net exposure to loss based upon the casualty value provisions		
Maximum Exposure	551	
Discounted Lease Payments, net	390	[1]
Variable Interest Entities Net Exposure	161	
Other FE Subsidiaries		
Net exposure to loss based upon the casualty value provisions		
Maximum Exposure	561	
Discounted Lease Payments, net	326	[1]
Variable Interest Entities Net Exposure	$ 235	

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.4 billion.

Segment Information (Details) (USD $) In Millions, unless otherwise specified	3 Months Ended			9 Months Ended				
	Sep. 30, 2012		Sep. 30, 2011		Sep. 30, 2012		Sep. 30, 2011		Dec. 31, 2011
Segment Financial Information									
External revenues	$ 4,311		$ 4,707		$ 12,256		$ 12,299		
Internal revenues	0		12		2		56		
Total revenues	4,311	[1]	4,719	[1]	12,258	[1]	12,355	[1]	
Depreciation and amortization	343		419		1,057		1,153		
Investment income	39		48		63		100		
Net interest charges	212		250		696		708		
Income taxes	309		325		658		550		
Net income	425		530		919		770		
Total assets	48,738		48,673		48,738		48,673		47,326
Total goodwill	6,444		6,428		6,444		6,428		6,441
Property additions	775		500		1,686		1,464		
Regulated Distribution									
Segment Financial Information									
External revenues	2,438		2,864		6,857		7,496		
Internal revenues	0		1		0		1		
Total revenues	2,438		2,865		6,857		7,497		
Depreciation and amortization	202		273		636		746		
Investment income	20		28		62		76		
Net interest charges	132		133		396		389		
Income taxes	168		164		355		322		
Net income	286	[2]	280		603	[2]	547		
Total assets	26,122		26,802		26,122		26,802		
Total goodwill	5,025		5,025		5,025		5,025		
Property additions	308		234		751		615		
Regulated Transmission									
Segment Financial Information									
External revenues	187		181		557		476		
Internal revenues	0		0		0		0		
Total revenues	187		181		557		476		
Depreciation and amortization	28		31		89		81		
Investment income	0		0		1		0		
Net interest charges	22		23		68		64		
Income taxes	35		32		101		79		
Net income	59		56		171		136		
Total assets	4,519		4,246		4,519		4,246		
Total goodwill	526		526		526		526		
Property additions	47		80		169		250		
Competitive Energy Services									

Segment Financial Information				
External revenues	1,719	1,714	4,942	4,450
Internal revenues	210	315	686	976
Total revenues	1,929	2,029	5,628	5,426
Depreciation and amortization	105	110	307	307
Investment income	36	28	48	49
Net interest charges	62	73	175	195
Income taxes	76	142	173	163
Net income	129	242	295	278
Total assets	16,846	16,809	16,846	16,809
Total goodwill	893	877	893	877
Property additions	412	186	715	543
Other/Corporate				
Segment Financial Information				
External revenues	(30)	(40)	(78)	(93)
Internal revenues	0	0	0	0
Total revenues	(30)	(40)	(78)	(93)
Depreciation and amortization	8	5	25	19
Investment income	(1)	0	(1)	1
Net interest charges	(4)	21	57	60
Income taxes	(9)	(23)	(49)	(53)
Net income	(11)	(40)	(82)	(145)
Total assets	1,251	816	1,251	816
Total goodwill	0	0	0	0
Property additions	8	0	51	56
Reconciling Adjustments				
Segment Financial Information				
External revenues	(3)	(12)	(22)	(30)
Internal revenues	(210)	(304)	(684)	(921)
Total revenues	(213)	(316)	(706)	(951)
Depreciation and amortization	0	0	0	0
Investment income	(16)	(8)	(47)	(26)
Net interest charges	0	0	0	0
Income taxes	39	10	78	39
Net income	(38)	(8)	(68)	(46)
Total assets	0	0	0	0
Total goodwill	0	0	0	0
Property additions	$ 0	$ 0	$ 0	$ 0

[1] Includes excise tax collections of $123 million and $137 million in the three months ended September 30, 2012 and 2011, respectively, and $351 million and $371 million in the nine months ended September 30, 2012 and 2011, respectively.

[2] Regulated Distribution net income for the three and nine months ended September 30, 2012, include adjustments of $21.8 million and $15.1 million, respectively, from capitalizing various construction activities

of the Allegheny Utilities that were previously expensed. The effect of these adjustments was not material to the current or previous periods.

Fair Value Measurements (Details 5) (Debt Securities, USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Amortized cost basis, unrealized gains and losses, and approximate fair values of investments in held-to-maturity securities		
Cost Basis	$ 210	$ 402
Unrealized Gains	58	50
Fair Value	268	452
OE		
Amortized cost basis, unrealized gains and losses, and approximate fair values of investments in held-to-maturity securities		
Cost Basis	148	163
Unrealized Gains	33	21
Fair Value	$ 181	$ 184

Pensions and Other Postemployment Benefits (Details 1) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Pensions				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	$ 14	$ 14	$ 41	$ 48
Pensions | FES				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	12	7	33	21
Pensions | OE				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	(1)	(2)	(3)	(6)
Pensions | JCP&L				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	(2)	(3)	(5)	(8)
OPEB				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	(30)	(31)	(92)	(97)
OPEB | FES				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	(8)	(8)	(24)	(24)
OPEB | OE				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	(5)	(5)	(16)	(16)
OPEB | JCP&L				
Net Periodic Pension and OPEB Costs (Credits)				
Net periodic benefit costs (credits)	$ (3)	$ (2)	$ (7)	$ (7)

Earnings Per Share (Tables)

	9 Months Ended Sep. 30, 2012

Earnings Per Share [Abstract]

Reconciliation of basic and diluted earnings per share

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 September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
	(In millions, except per share amounts)			
Weighted average number of basic shares outstanding	417	418	418	392
Assumed exercise of dilutive stock options and awards[(1)]	2	2	1	2
Weighted average number of diluted shares outstanding	419	420	419	394
Earnings Available to FirstEnergy Corp.	$ 425	$ 532	$ 918	$ 787
Basic earnings per share of common stock	$ 1.02	$ 1.27	$ 2.20	$ 2.01
Diluted earnings per share of common stock	$ 1.01	$ 1.27	$ 2.19	$ 2.00

[(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 nine months ended September 30, 2012 and 2011.

Fair Value Measurements (Details Textuals) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Fair Value of Financial Instruments [Line Items]		
Investment excludes Receivables, Payables and Accrued income	$ 43	$ (52)
Cash balance excluded from available for sale securities	596	164
Investments not required to be disclosed	709	693
FES		
Fair Value of Financial Instruments [Line Items]		
Investment excludes Receivables, Payables and Accrued income	47	(58)
Cash balance excluded from available for sale securities	443	74
Notes receivable, fair value	4	
OE		
Fair Value of Financial Instruments [Line Items]		
Investment excludes Receivables, Payables and Accrued income	1	1
Cash balance excluded from available for sale securities	3	2
JCP&L		
Fair Value of Financial Instruments [Line Items]		
Investment excludes Receivables, Payables and Accrued income	1	2
Cash balance excluded from available for sale securities	$ 51	$ 19

Segment Information (Details Textuals) (USD $) In Millions, unless otherwise specified	3 Months Ended Sep. 30, 2012		9 Months Ended Sep. 30, 2012	
Segment Reporting Information [Line Items]				
Reportable Operating Segments			3	
Number of existing utility operating companies			10	
Regulated Distribution				
Segment Reporting Information [Line Items]				
Number of customers served by utility operating companies			6,000,000	
Number of square miles in service area	65,000		65,000	
Regulated Distribution | Net Income | Previously Expensing Costs to be Capitalized				
Segment Reporting Information [Line Items]				
Error correction, corrected in current period	$ 21.8	[1]	$ 15.1	[1]
Competitive Energy Services				
Segment Reporting Information [Line Items]				
Megawatts of net demonstrated capacity of competitive segment	17,000		17,000	
Competitive Energy Services | Unregulated Plants Expected to be Closed by 9/1/2012				
Segment Reporting Information [Line Items]				
Megawatt capacity of plants expected to be closed	2,700		2,700	

[1] Regulated Distribution net income for the three and nine months ended September 30, 2012, include adjustments of $21.8 million and $15.1 million, respectively, from capitalizing various construction activities of the Allegheny Utilities that were previously expensed. The effect of these adjustments was not material to the current or previous periods.

Variable Interest Entities	9 Months Ended Sep. 30, 2012
Variable Interest Entities [Abstract]	
VARIABLE INTEREST ENTITIES	

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 third 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 $253 million was outstanding as of September 30, 2012; and special purpose limited liability companies of MP and PE created to issue environmental control bonds that were used to construct environmental control facilities, of which $493 million was outstanding as of September 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 nine months ended September 30, 2012, was primarily due to net income attributable to noncontrolling interests of $1 million, offset by $4 million in distributions 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, Pinesdale LLC, 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 Global Holding, the holding company for 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 that was to be constructed by PATH-WV.

On August 24, 2012, PJM officially removed the PATH project from its long-range expansion plans. Citing a slow economy for reducing the projected growth in electricity use, PJM said its updated analysis no longer indicates a need for the $2.1 billion, 275-mile transmission line to maintain grid stability. A joint venture between Allegheny and AEP, the project was suspended by PJM in February 2011. PATH expects to recover approximately $121 million of costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) over the next 5 years, of which $62 million relates to PATH-Allegheny and approximately $59 million relates to PATH-WV. See Note 9, Regulatory Matters, of the Combined Notes to the Consolidated Financial Statements for additional information on the abandonment of PATH.

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 as of September 30, 2012. In October 2012, one of JCP&L's long-term power purchase agreements with a NUG entity ended. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities.

FirstEnergy has determined that for all but 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 FE subsidiaries during the three months ended September 30, 2012, were $19 million, $30 million and $16 million for JCP&L, PE and WP, respectively, and $46 million, $89 million and $49 million for the nine months ended September 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, during the three months ended September 30, 2011, were $44 million, $31 million, and $14 million, respectively, and $164 million, $89 million and $40 million for the nine months ended September 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 September 30, 2012, WP’s reserve for this adverse purchase power commitment was $45 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.

On August 24, 2012, NGC repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $108 million. Additionally, during the third quarter of 2012, FGCO acquired certain lessor equity interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for an aggregate purchase price of approximately $95.4 million; during the fourth quarter of 2012, additional equity purchases of $37.6 million, as well as an early buyout for $23.6 million occurred.

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 as of September 30, 2012:

	Maximum Exposure	Discounted Lease	Net Exposure

		Payments, net[1]	
		(In millions)	
FES	$ 1,339	$ 1,123	$ 216
OE	551	390	161
Other FE subsidiaries	561	326	235

(1) The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.4 billion.

Fair Value Measurements (Details) (Recurring, USD $) In Millions, unless otherwise specified	Sep. 30, 2012		Dec. 31, 2011	
Assets				
Fair value, assets	$ 2,908		$ 2,863	
Liabilities				
Fair value, liabilities	(630)		(619)	
Net assets (liabilities)	2,278	[1]	2,244	[1]
FES				
Assets				
Fair value, assets	1,498		1,530	
Liabilities				
Fair value, liabilities	(184)		(241)	
Net assets (liabilities)	1,314	[2]	1,289	[2]
OE				
Assets				
Fair value, assets	141	[3]	137	[3]
JCP&L				
Assets				
Fair value, assets	428		414	
Liabilities				
Fair value, liabilities	(267)		(147)	
Net assets (liabilities)	161	[4]	267	[4]
Commodity contracts | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(177)		(247)	
Commodity contracts | Derivative Liabilities | FES				
Liabilities				
Fair value, liabilities	(177)		(234)	
FTRs | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(11)		(23)	
FTRs | Derivative Liabilities | FES				
Liabilities				
Fair value, liabilities	(7)		(7)	
Non Utility Generation contract | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(300)	[5]	(349)	[5]
Non Utility Generation contract | Derivative Liabilities | JCP&L				
Liabilities				
Fair value, liabilities	(125)	[6]	(147)	[6]

LCAPP Contracts | Derivative Liabilities

Liabilities		
Fair value, liabilities	(142) [5]	0 [5]

LCAPP Contracts | Derivative Liabilities | JCP&L

Liabilities		
Fair value, liabilities	(142) [6]	0 [6]

Corporate debt securities

Assets		
Fair value, assets	1,012	1,544

Corporate debt securities | FES

Assets		
Fair value, assets	437	1,010

Corporate debt securities | OE

Assets		
Fair value, assets	0	3

Corporate debt securities | JCP&L

Assets		
Fair value, assets	139	144

Commodity contracts | Derivative Assets

Assets		
Fair value, assets	260	264

Commodity contracts | Derivative Assets | FES

Assets		
Fair value, assets	255	248

FTRs | Derivative Assets

Assets		
Fair value, assets	7	1

FTRs | Derivative Assets | FES

Assets		
Fair value, assets	5	1

Non Utility Generation contract | Derivative Assets

Assets		
Fair value, assets	18 [5]	56 [5]

Non Utility Generation contract | Derivative Assets | JCP&L

Assets		
Fair value, assets	1 [6]	4 [6]

Equity securities

Assets		
Fair value, assets	367 [7]	259 [7]

Equity securities | FES

Assets		
Fair value, assets	334 [7]	124 [7]

Equity securities | JCP&L

Assets				
Fair value, assets	0	[7]	30	[7]
Foreign government debt securities				
Assets				
Fair value, assets	60		3	
Foreign government debt securities | FES				
Assets				
Fair value, assets	50		3	
Foreign government debt securities | JCP&L				
Assets				
Fair value, assets	2		0	
U.S. government debt securities				
Assets				
Fair value, assets	184		148	
U.S. government debt securities | FES				
Assets				
Fair value, assets	21		7	
U.S. government debt securities | OE				
Assets				
Fair value, assets	138		132	
U.S. government debt securities | JCP&L				
Assets				
Fair value, assets	8		2	
U.S. state debt securities				
Assets				
Fair value, assets	314		314	
U.S. state debt securities | FES				
Assets				
Fair value, assets	0		5	
U.S. state debt securities | JCP&L				
Assets				
Fair value, assets	230		219	
Other				
Assets				
Fair value, assets	686	[8]	274	[8]
Other | FES				
Assets				
Fair value, assets	396	[8]	132	[8]
Other | OE				
Assets				
Fair value, assets	3	[8]	2	[8]
Other | JCP&L				
Assets				

Fair value, assets	48 [8]	15 [8]
Level 1		
Assets		
Fair value, assets	494	308
Liabilities		
Fair value, liabilities	0	0
Net assets (liabilities)	494 [1]	308 [1]
Level 1 | FES		
Assets		
Fair value, assets	337	124
Liabilities		
Fair value, liabilities	0	0
Net assets (liabilities)	337 [2]	124 [2]
Level 1 | OE		
Assets		
Fair value, assets	0 [3]	0 [3]
Level 1 | JCP&L		
Assets		
Fair value, assets	0	30
Liabilities		
Fair value, liabilities	0	0
Net assets (liabilities)	0 [4]	30 [4]
Level 1 | Commodity contracts | Derivative Liabilities		
Liabilities		
Fair value, liabilities	0	0
Level 1 | Commodity contracts | Derivative Liabilities | FES		
Liabilities		
Fair value, liabilities	0	0
Level 1 | FTRs | Derivative Liabilities		
Liabilities		
Fair value, liabilities	0	0
Level 1 | FTRs | Derivative Liabilities | FES		
Liabilities		
Fair value, liabilities	0	0
Level 1 | Non Utility Generation contract | Derivative Liabilities		
Liabilities		
Fair value, liabilities	0 [5]	0 [5]
Level 1 | Non Utility Generation contract | Derivative Liabilities | JCP&L		
Liabilities		
Fair value, liabilities	0 [6]	0 [6]
Level 1 | LCAPP Contracts | Derivative Liabilities		
Liabilities		

Fair value, liabilities	0	[5]	0	[5]
Level 1 | LCAPP Contracts | Derivative Liabilities | JCP&L				
Liabilities				
Fair value, liabilities	0	[6]	0	[6]
Level 1 | Corporate debt securities				
Assets				
Fair value, assets	0		0	
Level 1 | Corporate debt securities | FES				
Assets				
Fair value, assets	0		0	
Level 1 | Corporate debt securities | OE				
Assets				
Fair value, assets	0		0	
Level 1 | Corporate debt securities | JCP&L				
Assets				
Fair value, assets	0		0	
Level 1 | Commodity contracts | Derivative Assets				
Assets				
Fair value, assets	3		0	
Level 1 | Commodity contracts | Derivative Assets | FES				
Assets				
Fair value, assets	3		0	
Level 1 | FTRs | Derivative Assets				
Assets				
Fair value, assets	0		0	
Level 1 | FTRs | Derivative Assets | FES				
Assets				
Fair value, assets	0		0	
Level 1 | Non Utility Generation contract | Derivative Assets				
Assets				
Fair value, assets	0	[5]	0	[5]
Level 1 | Non Utility Generation contract | Derivative Assets | JCP&L				
Assets				
Fair value, assets	0	[6]	0	[6]
Level 1 | Equity securities				
Assets				
Fair value, assets	367	[7]	259	[7]
Level 1 | Equity securities | FES				
Assets				
Fair value, assets	334	[7]	124	[7]
Level 1 | Equity securities | JCP&L				
Assets				
Fair value, assets	0	[7]	30	[7]

Level 1 | Foreign government debt securities		
Assets		
Fair value, assets	0	0
Level 1 | Foreign government debt securities | FES		
Assets		
Fair value, assets	0	0
Level 1 | Foreign government debt securities | JCP&L		
Assets		
Fair value, assets	0	0
Level 1 | U.S. government debt securities		
Assets		
Fair value, assets	0	0
Level 1 | U.S. government debt securities | FES		
Assets		
Fair value, assets	0	0
Level 1 | U.S. government debt securities | OE		
Assets		
Fair value, assets	0	0
Level 1 | U.S. government debt securities | JCP&L		
Assets		
Fair value, assets	0	0
Level 1 | U.S. state debt securities		
Assets		
Fair value, assets	0	0
Level 1 | U.S. state debt securities | FES		
Assets		
Fair value, assets	0	0
Level 1 | U.S. state debt securities | JCP&L		
Assets		
Fair value, assets	0	0
Level 1 | Other		
Assets		
Fair value, assets	124 [8]	49 [8]
Level 1 | Other | FES		
Assets		
Fair value, assets	0 [8]	0 [8]
Level 1 | Other | OE		
Assets		
Fair value, assets	0 [8]	0 [8]
Level 1 | Other | JCP&L		
Assets		
Fair value, assets	0 [8]	0 [8]
Level 2		

Assets				
Fair value, assets	2,389		2,498	
Liabilities				
Fair value, liabilities	(177)		(247)	
Net assets (liabilities)	2,212	[1]	2,251	[1]
Level 2 | FES				
Assets				
Fair value, assets	1,156		1,405	
Liabilities				
Fair value, liabilities	(177)		(234)	
Net assets (liabilities)	979	[2]	1,171	[2]
Level 2 | OE				
Assets				
Fair value, assets	141	[3]	137	[3]
Level 2 | JCP&L				
Assets				
Fair value, assets	427		380	
Liabilities				
Fair value, liabilities	0		0	
Net assets (liabilities)	427	[4]	380	[4]
Level 2 | Commodity contracts | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(177)		(247)	
Level 2 | Commodity contracts | Derivative Liabilities | FES				
Liabilities				
Fair value, liabilities	(177)		(234)	
Level 2 | FTRs | Derivative Liabilities				
Liabilities				
Fair value, liabilities	0		0	
Level 2 | FTRs | Derivative Liabilities | FES				
Liabilities				
Fair value, liabilities	0		0	
Level 2 | Non Utility Generation contract | Derivative Liabilities				
Liabilities				
Fair value, liabilities	0	[5]	0	[5]
Level 2 | Non Utility Generation contract | Derivative Liabilities | JCP&L				
Liabilities				
Fair value, liabilities	0	[6]	0	[6]
Level 2 | LCAPP Contracts | Derivative Liabilities				
Liabilities				
Fair value, liabilities	0	[5]	0	[5]
Level 2 | LCAPP Contracts | Derivative Liabilities | JCP&L				
Liabilities				

Fair value, liabilities	0 [6]	0 [6]
Level 2 | Corporate debt securities		
Assets		
Fair value, assets	1,012	1,544
Level 2 | Corporate debt securities | FES		
Assets		
Fair value, assets	437	1,010
Level 2 | Corporate debt securities | OE		
Assets		
Fair value, assets	0	3
Level 2 | Corporate debt securities | JCP&L		
Assets		
Fair value, assets	139	144
Level 2 | Commodity contracts | Derivative Assets		
Assets		
Fair value, assets	257	264
Level 2 | Commodity contracts | Derivative Assets | FES		
Assets		
Fair value, assets	252	248
Level 2 | FTRs | Derivative Assets		
Assets		
Fair value, assets	0	0
Level 2 | FTRs | Derivative Assets | FES		
Assets		
Fair value, assets	0	0
Level 2 | Non Utility Generation contract | Derivative Assets		
Assets		
Fair value, assets	0 [5]	0 [5]
Level 2 | Non Utility Generation contract | Derivative Assets | JCP&L		
Assets		
Fair value, assets	0 [6]	0 [6]
Level 2 | Equity securities		
Assets		
Fair value, assets	0 [7]	0 [7]
Level 2 | Equity securities | FES		
Assets		
Fair value, assets	0 [7]	0 [7]
Level 2 | Equity securities | JCP&L		
Assets		
Fair value, assets	0 [7]	0 [7]
Level 2 | Foreign government debt securities		
Assets		
Fair value, assets	60	3

Level 2 | Foreign government debt securities | FES				
Assets				
Fair value, assets	50		3	
Level 2 | Foreign government debt securities | JCP&L				
Assets				
Fair value, assets	2		0	
Level 2 | U.S. government debt securities				
Assets				
Fair value, assets	184		148	
Level 2 | U.S. government debt securities | FES				
Assets				
Fair value, assets	21		7	
Level 2 | U.S. government debt securities | OE				
Assets				
Fair value, assets	138		132	
Level 2 | U.S. government debt securities | JCP&L				
Assets				
Fair value, assets	8		2	
Level 2 | U.S. state debt securities				
Assets				
Fair value, assets	314		314	
Level 2 | U.S. state debt securities | FES				
Assets				
Fair value, assets	0		5	
Level 2 | U.S. state debt securities | JCP&L				
Assets				
Fair value, assets	230		219	
Level 2 | Other				
Assets				
Fair value, assets	562	[8]	225	[8]
Level 2 | Other | FES				
Assets				
Fair value, assets	396	[8]	132	[8]
Level 2 | Other | OE				
Assets				
Fair value, assets	3	[8]	2	[8]
Level 2 | Other | JCP&L				
Assets				
Fair value, assets	48	[8]	15	[8]
Level 3				
Assets				
Fair value, assets	25		57	
Liabilities				

Fair value, liabilities	(453)		(372)	
Net assets (liabilities)	(428)	[1]	(315)	[1]
Level 3 | FES				
Assets				
Fair value, assets	5		1	
Liabilities				
Fair value, liabilities	(7)		(7)	
Net assets (liabilities)	(2)	[2]	(6)	[2]
Level 3 | OE				
Assets				
Fair value, assets	0	[3]	0	[3]
Level 3 | JCP&L				
Assets				
Fair value, assets	1		4	
Liabilities				
Fair value, liabilities	(267)		(147)	
Net assets (liabilities)	(266)	[4]	(143)	[4]
Level 3 | Commodity contracts | Derivative Liabilities				
Liabilities				
Fair value, liabilities	0		0	
Level 3 | Commodity contracts | Derivative Liabilities | FES				
Liabilities				
Fair value, liabilities	0		0	
Level 3 | FTRs | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(11)		(23)	
Level 3 | FTRs | Derivative Liabilities | FES				
Liabilities				
Fair value, liabilities	(7)		(7)	
Level 3 | Non Utility Generation contract | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(300)	[5]	(349)	[5]
Level 3 | Non Utility Generation contract | Derivative Liabilities | JCP&L				
Liabilities				
Fair value, liabilities	(125)	[6]	(147)	[6]
Level 3 | LCAPP Contracts | Derivative Liabilities				
Liabilities				
Fair value, liabilities	(142)	[5]	0	[5]
Level 3 | LCAPP Contracts | Derivative Liabilities | JCP&L				
Liabilities				
Fair value, liabilities	(142)	[6]	0	[6]
Level 3 | Corporate debt securities				

Assets				
Fair value, assets	0		0	
Level 3 | Corporate debt securities | FES				
Assets				
Fair value, assets	0		0	
Level 3 | Corporate debt securities | OE				
Assets				
Fair value, assets	0		0	
Level 3 | Corporate debt securities | JCP&L				
Assets				
Fair value, assets	0		0	
Level 3 | Commodity contracts | Derivative Assets				
Assets				
Fair value, assets	0		0	
Level 3 | Commodity contracts | Derivative Assets | FES				
Assets				
Fair value, assets	0		0	
Level 3 | FTRs | Derivative Assets				
Assets				
Fair value, assets	7		1	
Level 3 | FTRs | Derivative Assets | FES				
Assets				
Fair value, assets	5		1	
Level 3 | Non Utility Generation contract | Derivative Assets				
Assets				
Fair value, assets	18	[5]	56	[5]
Level 3 | Non Utility Generation contract | Derivative Assets | JCP&L				
Assets				
Fair value, assets	1	[6]	4	[6]
Level 3 | Equity securities				
Assets				
Fair value, assets	0	[7]	0	[7]
Level 3 | Equity securities | FES				
Assets				
Fair value, assets	0	[7]	0	[7]
Level 3 | Equity securities | JCP&L				
Assets				
Fair value, assets	0	[7]	0	[7]
Level 3 | Foreign government debt securities				
Assets				
Fair value, assets	0		0	
Level 3 | Foreign government debt securities | FES				
Assets				

Fair value, assets	0	0
Level 3 | Foreign government debt securities | JCP&L		
Assets		
Fair value, assets	0	0
Level 3 | U.S. government debt securities		
Assets		
Fair value, assets	0	0
Level 3 | U.S. government debt securities | FES		
Assets		
Fair value, assets	0	0
Level 3 | U.S. government debt securities | OE		
Assets		
Fair value, assets	0	0
Level 3 | U.S. government debt securities | JCP&L		
Assets		
Fair value, assets	0	0
Level 3 | U.S. state debt securities		
Assets		
Fair value, assets	0	0
Level 3 | U.S. state debt securities | FES		
Assets		
Fair value, assets	0	0
Level 3 | U.S. state debt securities | JCP&L		
Assets		
Fair value, assets	0	0
Level 3 | Other		
Assets		
Fair value, assets	0 [8]	0 [8]
Level 3 | Other | FES		
Assets		
Fair value, assets	0 [8]	0 [8]
Level 3 | Other | OE		
Assets		
Fair value, assets	0 [8]	0 [8]
Level 3 | Other | JCP&L		
Assets		
Fair value, assets	$ 0 [8]	$ 0 [8]

[1] Excludes $43 million and $(52) million as of September 30, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

[2] Excludes $47 million and $(58) million as of September 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.

[3] Excludes $1 million and $1 million as of September 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.

[4] Excludes $1 million and $2 million as of September 30, 2012 and December 31, 2011 of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

[5] NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.

[6] NUG and LCAPP contracts are subject to regulatory accounting treatment and do not impact earnings.

[7] NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

[8] Primarily consists of short-term cash investments.

Goodwill (Details) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011	Sep. 30, 2011
Goodwill [Line Items]			
Goodwill	$ 6,444	$ 6,441	$ 6,428
Regulated Distribution			
Goodwill [Line Items]			
Goodwill	5,025		5,025
Regulated Transmission			
Goodwill [Line Items]			
Goodwill	526		526
Competitive Energy Services			
Goodwill [Line Items]			
Goodwill	$ 893		$ 877

Derivative Instruments (Tables)	9 Months Ended Sep. 30, 2012
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Fair value of derivatives instruments	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 September 30, 2012	Fair Value December 31, 2011	Derivative Liabilities	Fair Value September 30, 2012	Fair Value December 31, 2011
	(In millions)			*(In millions)*	
Power Contracts			Power Contracts		
Current Assets	$ 178	$ 185	Current Liabilities	$ (146)	$ (196)
Noncurrent Assets	79	79	Noncurrent Liabilities	(31)	(51)
FTRs			FTRs		
Current Assets	7	1	Current Liabilities	(9)	(22)
Noncurrent Assets	—	—	Noncurrent Liabilities	(2)	(1)
NUGs	18	56	NUGs	(300)	(349)
LCAPP	—	—	LCAPP	(142)	—
Other Current Assets	3	—	Other Current Liabilities	—	—
	$ 285	$ 321		$ (630)	$ (619)

Volume of First Energy's outstanding derivative transactions

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

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	33	38	(5)	MWH
FTRs	67	—	67	MWH
NUGs	16	—	16	MWH
LCAPP	408	—	408	MW
Natural Gas	16	—	16	BTUs

Effect of derivative instruments on statements of income and comprehensive income

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

Three Months Ended September 30	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$ (2)	$ —	$ —	$ —	$ (2)
2011					
Gain (Loss) Recognized in AOCI (Effective Portion)	$ —	$ —	$ —	$ —	$ —
Derivatives Not in a Hedging Relationship					
2012					

Unrealized Gain (Loss) Recognized in:										
Other Operating Expense	$	7	$	(5)	$	—	$	—	$	2
Interest Expense		—		—		20		—		20
Realized Gain (Loss) Reclassified to:										
Purchased Power Expense	$	(27)	$	—	$	—	$	—	$	(27)
Revenues		46		6		—		—		52
Other Operating Expense		—		(10)		—		—		(10)
Fuel Expense		—		—		—		3		3
Interest Expense		—		—		6		—		6
2011										
Unrealized Gain (Loss) Recognized in:										
Purchased Power Expense	$	27	$	—	$	—	$	—	$	27
Revenues		3		—		—		—		3
Other Operating Expense		(11)		(9)		1		—		(19)
Realized Gain (Loss) Reclassified to:										
Purchased Power Expense	$	(5)	$	—	$	—	$	—	$	(5)
Revenues		(39)		20		(1)		—		(20)
Other Operating Expense		—		(22)		—		—		(22)

	Nine Months Ended September 30									
	Power Contracts		FTRs		Interest Rate Swaps		Other		Total	
					(In millions)					
Derivatives in a Hedging Relationship										
2012										
Loss Recognized in AOCI (Effective Portion)	$	(6)	$	—	$	—	$	—	$	(6)
2011										
Gain Recognized in AOCI (Effective Portion)	$	4	$	—	$	1	$	—	$	5
Effective Gain (Loss) Reclassified to:										
Purchased Power Expense		16		—		—		—		16
Revenues		(12)		—		—		—		(12)
Derivatives Not in a Hedging Relationship										
2012										
Unrealized Gain Recognized in:										
Other Operating Expense	$	69	$	12	$	—	$	3	$	84
Realized Gain (Loss) Reclassified to:										
Purchased Power Expense	$	(248)	$	—	$	—	$	—	$	(248)
Revenues		260		18		—		—		278
Other Operating Expense		—		(51)		—		—		(51)
Fuel Expense		—		—		—		2		2
Interest Expense		—		—		6		—		6
2011										
Unrealized Gain (Loss) Recognized in:										

Purchased Power Expense	$ 88	$ —	$ —	$ —	$ 88
Revenues	(1)	—	—	—	(1)
Other Operating Expense	(65)	2	2	—	(61)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (41)	$ —	$ —	$ —	$ (41)
Revenues	(69)	36	(2)	—	(35)
Other Operating Expense	—	(77)	—	—	(77)

Derivative instruments subject to regulatory accounting

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

	Three Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
			(In millions)		
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Gain (Loss) on Derivative Instrument	$ (50)	$ 3	$ —	$ —	$ (47)
Realized Gain (Loss) on Derivative Instrument	61	—	(1)	—	60
2011					
Unrealized Loss on Derivative Instrument	$ (89)	$ —	$ (3)	$ —	$ (92)
Realized Gain (Loss) on Derivative Instrument	53	—	(3)	—	50

	Nine Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
			(In millions)		
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Loss on Derivative Instrument	$(183)	$ (142)	$ —	$ —	$(325)
Realized Gain on Derivative Instrument	194	—	7	—	201
2011					
Unrealized Loss on Derivative Instrument	$(325)	$ —	$ —	$ —	$(325)
Realized Gain (Loss) on Derivative Instrument	187	—	(4)	(10)	173

Reconciliation of changes in the fair value of certain contracts that are deferred

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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 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 July 1, 2012	$ (293)	$ (145)	$ —	$ —	$ (438)
Additions/Change in value of existing contracts	(50)	3	—	—	(47)
Settled contracts	61	—	(1)	—	60
Outstanding net asset (liability) as of September 30, 2012	$ (282)	$ (142)	$ (1)	$ —	$ (425)

Outstanding net asset (liability) as of July 1, 2011	$	(447)	$	—	$	2	$	—	$	(445)
Additions/Change in value of existing contracts		(89)		—		(3)		—		(92)
Settled contracts		53		—		(3)		—		50
Outstanding net asset (liability) as of September 30, 2011	$	(483)	$	—	$	(4)	$	—	$	(487)

	Nine Months Ended September 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 January 1, 2012	$	(293)	$	—	$	(8)	$	—	$	(301)
Additions/Change in value of existing contracts		(183)		(142)		—		—		(325)
Settled contracts		194		—		7		—		201
Outstanding net asset (liability) as of September 30, 2012	$	(282)	$	(142)	$	(1)	$	—	$	(425)
Outstanding net asset (liability) as of January 1, 2011	$	(345)	$	—	$	—	$	10	$	(335)
Additions/Change in value of existing contracts		(325)		—		—		—		(325)
Settled contracts		187		—		(4)		(10)		173
Outstanding net asset (liability) as of September 30, 2011	$	(483)	$	—	$	(4)	$	—	$	(487)

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

9 Months Ended

Fair Value Measurements (Details 2) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012 FTRs	Dec. 31, 2011 FTRs	Dec. 31, 2010 FTRs	Sep. 30, 2012 FTRs FES	Dec. 31, 2011 FTRs FES	Dec. 31, 2010 FTRs FES	Sep. 30, 2012 Non Utility Generation contract	Dec. 31, 2011 Non Utility Generation contract	Dec. 31, 2010 Non Utility Generation contract	Sep. 30, 2012 Non Utility Generation contract JCP&L	Dec. 31, 2011 Non Utility Generation contract JCP&L	Dec. 31, 2010 Non Utility Generation contract JCP&L	Dec. 31, 2011 LCAPP Contracts	Dec. 31, 2010 LCAPP Contracts
Fair Value Inputs, Assets and Liabilities, Quantitative Information [Line Items]														
Fair Value	$ (4)	$ (22)	$ 0	$ (2)	$ (6)	$ 0	$ (282) [1]	$ (292) [1]	$ (344) [1]	$ (124) [1]	$ (143)	$ (227)	$ 0 [1]	$ 0 [1]
Fair Value Inputs, RTO Auction Clearing Prices														
Fair Value Inputs, Generation														
Fair Value Inputs, Power, Regional Prices														

Fair Value Measurements (Details 2) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012 LCAPP Contracts JCP&L	Dec. 31, 2011 LCAPP Contracts JCP&L	Dec. 31, 2010 LCAPP Contracts JCP&L	Sep. 30, 2012 Level 3 LCAPP Contracts	Sep. 30, 2012 Model Level 3 FTRs	Sep. 30, 2012 Model Level 3 FTRs FES	Sep. 30, 2012 Model Level 3 Non Utility Generation contract	Sep. 30, 2012 Model Level 3 Non Utility Generation contract JCP&L	Sep. 30, 2012 Model Level 3 LCAPP Contracts	Sep. 30, 2012 Model Level 3 LCAPP Contracts JCP&L	Sep. 30, 2012 Model Level 3 Minimum FTRs	Sep. 30, 2012 Model Level 3 Minimum FTRs FES	Sep. 30, 2012 Model Level 3 Minimum Non Utility Generation contract MWh	Sep. 30, 2012 Model Level 3 Minimum Non Utility Generation contract JCP&L MWh
Fair Value Inputs, Assets and Liabilities, Quantitative Information [Line Items]														
Fair Value	$ (142)	$ 0	$ 0	$ (142) [1]	$ (4)	$ (2)	$ (282) [1]	$ (124)	$ (142)	$ (142) [1]				
Fair Value Inputs, RTO Auction Clearing Prices											(3.80)	(3.80)		
Fair Value Inputs, Generation													700	95,000
Fair Value Inputs, Power, Regional Prices													43.40	45.50

Fair Value Measurements (Details 2) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012 Model Level 3 Minimum LCAPP Contracts	Sep. 30, 2012 Model Level 3 Minimum LCAPP Contracts JCP&L	Sep. 30, 2012 Model Level 3 Maximum FTRs	Sep. 30, 2012 Model Level 3 Maximum FTRs FES	Sep. 30, 2012 Model Level 3 Maximum Non Utility Generation contract MWh	Sep. 30, 2012 Model Level 3 Maximum Non Utility Generation contract JCP&L MWh	Sep. 30, 2012 Model Level 3 Maximum LCAPP Contracts	Sep. 30, 2012 Model Level 3 Maximum LCAPP Contracts JCP&L	Sep. 30, 2012 Model Level 3 Weighted Average [Member] FTRs	Sep. 30, 2012 Model Level 3 Weighted Average [Member] FTRs FES	Sep. 30, 2012 Model Level 3 Weighted Average [Member] Non Utility Generation contract MWh	Sep. 30, 2012 Model Level 3 Weighted Average [Member] Non Utility Generation contract JCP&L MWh	Sep. 30, 2012 Model Level 3 Weighted Average [Member] LCAPP Contracts	Sep. 30, 2012 Model Level 3 Weighted Average [Member] LCAPP Contracts JCP&L
Fair Value Inputs, Assets and Liabilities, Quantitative Information [Line Items]														
Fair Value														
Fair Value Inputs, RTO Auction Clearing Prices			6.40	6.40					0.50	0.30				
Fair Value Inputs, Generation					6,748,000	1,324,000					3,211,000	405,000		
Fair Value Inputs, Power, Regional Prices	158.60	158.60			57.30	59.50	197.30	197.30			51.90	54.10	174.50	174.50

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

Supplemental Guarantor Information (Details) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Consolidating Statements of Income				
Revenues	$ 2,624	$ 3,041	$ 7,414	$ 7,966
OPERATING EXPENSES:				
Fuel	636	632	1,833	1,720
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME (LOSS)	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Investment income	39	48	63	100
Interest expense	(230)	(267)	(750)	(763)
Capitalized interest	18	17	54	55
Total other income (expense)	(173)	(202)	(633)	(608)
INCOME (LOSS) BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES (BENEFITS)	309	325	658	550
NET INCOME	425	530	919	770
OTHER COMPREHENSIVE INCOME (LOSS):				
NET INCOME	425	530	919	770
Pension and OPEB prior service costs	(47)	(48)	(148)	(44)
Amortized gain (loss) on derivative hedges	0	2	1	13
Change in unrealized gain on available-for-sale securities	1	(26)	13	(7)
Other comprehensive income (loss)	(46)	(72)	(134)	(38)
Income taxes (benefits) on other comprehensive income (loss)	(24)	(26)	(75)	(12)
Other comprehensive income (loss), net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
FES Corp				
Consolidating Statements of Income				
Revenues	1,523	1,445	4,443	4,087
OPERATING EXPENSES:				
Fuel	0	6	0	13
Other operating expenses	130	162	313	483
Provision for depreciation	1	1	3	3
General taxes	20	19	60	46
Impairment of long-lived assets		0		0
Total operating expenses	1,692	1,549	4,959	4,622
OPERATING INCOME (LOSS)	(169)	(104)	(516)	(535)

OTHER INCOME (EXPENSE):				
Investment income	1	0	2	1
Miscellaneous income, including net income from equity investees	317	196	854	570
Capitalized interest	0	0	0	0
Total other income (expense)	288	172	770	498
INCOME (LOSS) BEFORE INCOME TAXES	119	68	254	(37)
INCOME TAXES (BENEFITS)	18	(52)	32	(231)
NET INCOME	101	120	222	194
OTHER COMPREHENSIVE INCOME (LOSS):				
NET INCOME	101	120	222	194
Pension and OPEB prior service costs	(5)	(5)	(2)	(14)
Amortized gain (loss) on derivative hedges	(2)	(1)	(6)	4
Change in unrealized gain on available-for-sale securities	(2)	(22)	11	(7)
Other comprehensive income (loss)	(9)	(28)	3	(17)
Income taxes (benefits) on other comprehensive income (loss)	(3)	(11)	1	(7)
Other comprehensive income (loss), net of tax	(6)	(17)	2	(10)
COMPREHENSIVE INCOME	95	103	224	184
FES Corp | Affiliates				
OPERATING EXPENSES:				
Purchased power	1,042	1,031	3,163	3,118
OTHER INCOME (EXPENSE):				
Interest expense	(5)	0	(14)	(1)
FES Corp | Non-Affiliates				
OPERATING EXPENSES:				
Purchased power	499	330	1,420	959
OTHER INCOME (EXPENSE):				
Interest expense	(25)	(24)	(72)	(72)
FGCO				
Consolidating Statements of Income				
Revenues	617	686	1,795	1,964
OPERATING EXPENSES:				
Fuel	248	323	824	883
Other operating expenses	79	94	271	313
Provision for depreciation	30	33	90	96
General taxes	10	9	28	28
Impairment of long-lived assets		2		22
Total operating expenses	367	463	1,213	1,352
OPERATING INCOME (LOSS)	250	223	582	612
OTHER INCOME (EXPENSE):				
Investment income	5	0	14	1
Miscellaneous income, including net income from equity investees	0	16	19	18

Capitalized interest	1	3	3	13
Total other income (expense)	(23)	(8)	(48)	(52)
INCOME (LOSS) BEFORE INCOME TAXES	227	215	534	560
INCOME TAXES (BENEFITS)	(11)	83	(19)	208
NET INCOME	238	132	553	352
OTHER COMPREHENSIVE INCOME (LOSS):				
NET INCOME	238	132	553	352
Pension and OPEB prior service costs	(4)	(4)	(1)	(12)
Amortized gain (loss) on derivative hedges	0	0	0	0
Change in unrealized gain on available-for-sale securities	0	0	0	0
Other comprehensive income (loss)	(4)	(4)	(1)	(12)
Income taxes (benefits) on other comprehensive income (loss)	(2)	(2)	(1)	(6)
Other comprehensive income (loss), net of tax	(2)	(2)	0	(6)
COMPREHENSIVE INCOME	236	130	553	346
FGCO | Affiliates				
OPERATING EXPENSES:				
Purchased power	0	4	0	15
OTHER INCOME (EXPENSE):				
Interest expense	(2)	(1)	(5)	(2)
FGCO | Non-Affiliates				
OPERATING EXPENSES:				
Purchased power	0	(2)	0	(5)
OTHER INCOME (EXPENSE):				
Interest expense	(27)	(26)	(79)	(82)
Nuclear Generation Corp				
Consolidating Statements of Income				
Revenues	395	371	1,262	1,233
OPERATING EXPENSES:				
Fuel	55	57	154	149
Other operating expenses	122	122	410	435
Provision for depreciation	41	36	114	112
General taxes	5	3	16	17
Impairment of long-lived assets		0		0
Total operating expenses	290	273	883	902
OPERATING INCOME (LOSS)	105	98	379	331
OTHER INCOME (EXPENSE):				
Investment income	37	28	49	48
Miscellaneous income, including net income from equity investees	0	0	0	0
Capitalized interest	8	5	24	15
Total other income (expense)	29	16	34	12
INCOME (LOSS) BEFORE INCOME TAXES	134	114	413	343
INCOME TAXES (BENEFITS)	59	45	124	131

NET INCOME	75	69	289	212
OTHER COMPREHENSIVE INCOME (LOSS):				
NET INCOME	75	69	289	212
Pension and OPEB prior service costs	0	0	0	0
Amortized gain (loss) on derivative hedges	0	0	0	0
Change in unrealized gain on available-for-sale securities	(1)	(22)	12	(7)
Other comprehensive income (loss)	(1)	(22)	12	(7)
Income taxes (benefits) on other comprehensive income (loss)	0	(9)	5	(3)
Other comprehensive income (loss), net of tax	(1)	(13)	7	(4)
COMPREHENSIVE INCOME	74	56	296	208
Nuclear Generation Corp | Affiliates				
OPERATING EXPENSES:				
Purchased power	67	55	189	189
OTHER INCOME (EXPENSE):				
Interest expense	(1)	(1)	(3)	(2)
Nuclear Generation Corp | Non-Affiliates				
OPERATING EXPENSES:				
Purchased power	0	0	0	0
OTHER INCOME (EXPENSE):				
Interest expense	(15)	(16)	(36)	(49)
Eliminations				
Consolidating Statements of Income				
Revenues	(978)	(1,035)	(2,971)	(3,133)
OPERATING EXPENSES:				
Fuel	0	0	0	0
Other operating expenses	12	12	37	37
Provision for depreciation	(1)	(1)	(4)	(4)
General taxes	0	0	0	0
Impairment of long-lived assets		0		0
Total operating expenses	(967)	(1,024)	(2,938)	(3,100)
OPERATING INCOME (LOSS)	(11)	(11)	(33)	(33)
OTHER INCOME (EXPENSE):				
Investment income	(5)	0	(15)	0
Miscellaneous income, including net income from equity investees	(316)	(203)	(848)	(571)
Capitalized interest	0	0	0	0
Total other income (expense)	(300)	(188)	(801)	(524)
INCOME (LOSS) BEFORE INCOME TAXES	(311)	(199)	(834)	(557)
INCOME TAXES (BENEFITS)	2	2	8	7
NET INCOME	(313)	(201)	(842)	(564)
OTHER COMPREHENSIVE INCOME (LOSS):				
NET INCOME	(313)	(201)	(842)	(564)
Pension and OPEB prior service costs	4	4	1	12

Amortized gain (loss) on derivative hedges	0	0	0	0
Change in unrealized gain on available-for-sale securities	1	22	(12)	7
Other comprehensive income (loss)	5	26	(11)	19
Income taxes (benefits) on other comprehensive income (loss)	2	11	(4)	9
Other comprehensive income (loss), net of tax	3	15	(7)	10
COMPREHENSIVE INCOME	(310)	(186)	(849)	(554)
Eliminations | Affiliates				
OPERATING EXPENSES:				
Purchased power	(978)	(1,035)	(2,971)	(3,133)
OTHER INCOME (EXPENSE):				
Interest expense	5	0	15	0
Eliminations | Non-Affiliates				
OPERATING EXPENSES:				
Purchased power	0	0	0	0
OTHER INCOME (EXPENSE):				
Interest expense	16	15	47	47
FES				
Consolidating Statements of Income				
Revenues	1,557	1,467	4,529	4,151
OPERATING EXPENSES:				
Fuel	303	386	978	1,045
Other operating expenses	343	390	1,031	1,268
Provision for depreciation	71	69	203	207
General taxes	35	31	104	91
Impairment of long-lived assets	0	2	0	22
Total operating expenses	1,382	1,261	4,117	3,776
OPERATING INCOME (LOSS)	175	206	412	375
OTHER INCOME (EXPENSE):				
Investment income	38	28	50	50
Miscellaneous income, including net income from equity investees	1	9	25	17
Capitalized interest	9	8	27	28
Total other income (expense)	(6)	(8)	(45)	(66)
INCOME (LOSS) BEFORE INCOME TAXES	169	198	367	309
INCOME TAXES (BENEFITS)	68	78	145	115
NET INCOME	101	120	222	194
OTHER COMPREHENSIVE INCOME (LOSS):				
NET INCOME	101	120	222	194
Pension and OPEB prior service costs	(5)	(5)	(2)	(14)
Amortized gain (loss) on derivative hedges	(2)	(1)	(6)	4
Change in unrealized gain on available-for-sale securities	(2)	(22)	11	(7)
Other comprehensive income (loss)	(9)	(28)	3	(17)

Income taxes (benefits) on other comprehensive income (loss)	(3)	(11)	1	(7)
Other comprehensive income (loss), net of tax	(6)	(17)	2	(10)
COMPREHENSIVE INCOME	95	103	224	184
FES | Affiliates				
OPERATING EXPENSES:				
Purchased power	131	55	381	189
OTHER INCOME (EXPENSE):				
Interest expense	(3)	(2)	(7)	(5)
FES | Non-Affiliates				
OPERATING EXPENSES:				
Purchased power	499	328	1,420	954
OTHER INCOME (EXPENSE):				
Interest expense	$ (51)	$ (51)	$ (140)	$ (156)

Derivative Instruments (Details 3) (Not Designated as Hedging Instrument [Member], Subject to Regulatory Accounting, Excluded from Earnings, USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Derivative [Line Items]				
Unrealized Gain (Loss) on Derivative Instrument	$ (47)	$ (92)	$ (325)	$ (325)
Realized Gain (Loss) on Derivative Instrument	60	50	201	173
NUGs				
Derivative [Line Items]				
Unrealized Gain (Loss) on Derivative Instrument	(50)	(89)	(183)	(325)
Realized Gain (Loss) on Derivative Instrument	61	53	194	187
LCAPP				
Derivative [Line Items]				
Unrealized Gain (Loss) on Derivative Instrument	3	0	(142)	0
Realized Gain (Loss) on Derivative Instrument	0	0	0	0
Regulated FTRs				
Derivative [Line Items]				
Unrealized Gain (Loss) on Derivative Instrument	0	(3)	0	0
Realized Gain (Loss) on Derivative Instrument	(1)	(3)	7	(4)
Other				
Derivative [Line Items]				
Unrealized Gain (Loss) on Derivative Instrument	0	0	0	0
Realized Gain (Loss) on Derivative Instrument	$ 0	$ 0	$ 0	$ (10)

Income Taxes (Details) (USD $) In Millions, unless otherwise specified	3 Months Ended	9 Months Ended			3 Months Ended	9 Months Ended
	Jun. 30, 2011	Sep. 30, 2012	Sep. 30, 2011	Dec. 31, 2011	Mar. 31, 2011 Allegheny	Sep. 30, 2012 Allegheny
Income Tax Contingency [Line Items]						
Previously unrecognized tax benefit, impact on effective tax rate from settlement with authorities		$ 3				
Decrease in unrecognized tax benefits						21
Income tax benefits on settlement of recognized research and development claim	30					
Tax benefits arising from favorable affected tax rate included in Research and development settlement			5			
Unrecognized tax benefits expected to resolved within the next twelve month		40				
Unrecognized benefits (if recognized) affecting effective tax rate		6	6			
Increase in accrued interest					6	
Accrued Interest		12		11		
Change in effective tax rate as a result of non-deductible portion of merger transaction and integration costs			$ 28			

Consolidated Balance Sheets (Unaudited) (FirstEnergy Solutions Corp.) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
CURRENT ASSETS:		
Cash and cash equivalents	$ 150	$ 202
Receivables-		
Customers, net of allowance for uncollectible accounts	1,604	1,525
Other, net of allowance for uncollectible accounts	227	269
Materials and supplies	875	811
Derivatives	212	235
Prepayments and other	190	122
Total current assets	3,709	3,355
PROPERTY, PLANT AND EQUIPMENT:		
In service	41,756	40,122
Less - Accumulated provision for depreciation	12,434	11,839
Property, plant and equipment in service net of accumulated provision for depreciation	29,322	28,283
Construction work in progress	2,119	2,054
Total net property, plant and equipment	31,441	30,337
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,203	2,112
Other	1,038	1,008
Total other property and investments	3,451	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,444	6,441
Other	1,580	1,641
Total deferred charges and other assets	10,137	10,112
Total assets	48,738	47,326
CURRENT LIABILITIES:		
Currently payable long-term debt	1,473	1,621
Accounts payable-		
Accrued taxes	508	558
Derivatives	155	218
Other	942	900
Total current liabilities	5,920	4,855
Common stockholders' equity-		
Common stock	42	42
Accumulated other comprehensive income	367	426
Retained earnings (Accumulated deficit)	3,266	3,047
Total common stockholders' equity	13,433	13,280
Long-term debt and other long-term obligations	15,627	15,716
Total capitalization	29,076	29,015

NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	900	925
Accumulated deferred income taxes	6,543	5,670
Asset retirement obligations	1,574	1,497
Retirement benefits	2,271	2,823
Other	1,904	2,072
Total noncurrent liabilities	13,742	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	48,738	47,326
FES		
CURRENT ASSETS:		
Cash and cash equivalents	3	7
Receivables-		
Customers, net of allowance for uncollectible accounts	485	424
Affiliated companies	402	600
Other, net of allowance for uncollectible accounts	103	61
Notes receivable from affiliated companies	438	383
Materials and supplies	533	492
Derivatives	209	219
Prepayments and other	137	38
Total current assets	2,310	2,224
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,638	10,983
Less - Accumulated provision for depreciation	4,312	4,110
Property, plant and equipment in service net of accumulated provision for depreciation	7,326	6,873
Construction work in progress	1,055	1,014
Total net property, plant and equipment	8,381	7,887
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,286	1,223
Other	16	7
Total other property and investments	1,302	1,230
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	114	123
Goodwill	24	24
Property taxes	43	43
Unamortized sale and leaseback costs	111	80
Derivatives	78	79
Other	181	129
Total deferred charges and other assets	551	478
Total assets	12,544	11,819
CURRENT LIABILITIES:		
Currently payable long-term debt	1,074	905
Accounts payable-		

Affiliated companies	787	436
Other	174	220
Accrued taxes	83	227
Derivatives	153	189
Other	244	261
Total current liabilities	2,515	2,238
Common stockholders' equity-		
Common stock	1,571	1,570
Accumulated other comprehensive income	78	76
Retained earnings (Accumulated deficit)	2,153	1,931
Total common stockholders' equity	3,802	3,577
Long-term debt and other long-term obligations	3,085	2,799
Total capitalization	6,887	6,376
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	900	925
Accumulated deferred income taxes	501	286
Asset retirement obligations	950	904
Retirement benefits	183	356
Lease market valuation liability	87	171
Other	521	563
Total noncurrent liabilities	3,142	3,205
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	$ 12,544	$ 11,819

Derivative Instruments (Details 4) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Outstanding net asset (liability) [Roll Forward]				
Outstanding net asset (liability), Beginning Balance	$ (438) [1]	$ (445) [1]	$ (301) [1]	$ (335) [1]
Additions/Change in value of existing contracts	(47) [1]	(92) [1]	(325) [1]	(325) [1]
Settled contracts	60 [1]	50 [1]	201 [1]	173 [1]
Outstanding net asset (liability), Ending Balance	(425) [1]	(487) [1]	(425) [1]	(487) [1]
NUGs				
Outstanding net asset (liability) [Roll Forward]				
Outstanding net asset (liability), Beginning Balance	(293) [1]	(447) [1]	(293) [1]	(345) [1]
Additions/Change in value of existing contracts	(50) [1]	(89) [1]	(183) [1]	(325) [1]
Settled contracts	61 [1]	53 [1]	194 [1]	187 [1]
Outstanding net asset (liability), Ending Balance	(282) [1]	(483) [1]	(282) [1]	(483) [1]
LCAPP				
Outstanding net asset (liability) [Roll Forward]				
Outstanding net asset (liability), Beginning Balance	(145) [1]	0 [1]	0 [1]	0 [1]
Additions/Change in value of existing contracts	3 [1]	0 [1]	(142) [1]	0 [1]
Settled contracts	0 [1]	0 [1]	0 [1]	0 [1]
Outstanding net asset (liability), Ending Balance	(142) [1]	0 [1]	(142) [1]	0 [1]
Regulated FTRs				
Outstanding net asset (liability) [Roll Forward]				
Outstanding net asset (liability), Beginning Balance	0 [1]	2 [1]	(8) [1]	0 [1]
Additions/Change in value of existing contracts	0 [1]	(3) [1]	0 [1]	0 [1]
Settled contracts	(1) [1]	(3) [1]	7 [1]	(4) [1]
Outstanding net asset (liability), Ending Balance	(1) [1]	(4) [1]	(1) [1]	(4) [1]
Other				
Outstanding net asset (liability) [Roll Forward]				
Outstanding net asset (liability), Beginning Balance	0 [1]	0 [1]	0 [1]	10 [1]
Additions/Change in value of existing contracts	0 [1]	0 [1]	0 [1]	0 [1]
Settled contracts	0 [1]	0 [1]	0 [1]	(10) [1]
Outstanding net asset (liability), Ending Balance	$ 0 [1]	$ 0 [1]	$ 0 [1]	$ 0 [1]

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

Earnings Per Share (Details) (USD $) In Millions, except Per Share data, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Reconciliation of basic and diluted earnings per share of common stock				
Weighted average number of basic shares outstanding	417	418	418	392
Assumed exercise of dilutive stock options and awards	2 [1]	2 [1]	1 [1]	2 [1]
Weighted average number of diluted shares outstanding	419	420	419	394
Earnings available to FirstEnergy Corp.	$ 425	$ 532	$ 918	$ 787
Basic earnings per share of common stock, in dollars per share	$ 1.02	$ 1.27	$ 2.20	$ 2.01
Diluted earnings per share of common stock, in dollars per share	$ 1.01	$ 1.27	$ 2.19	$ 2.00

[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 nine months ended September 30, 2012 and 2011.

Commitments, Guarantees and Contingencies	9 Months Ended Sep. 30, 2012
Commitments and Contingencies Disclosure [Abstract]	
COMMITMENTS, GUARANTEES AND CONTINGENCIES	

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 September 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).

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, fuel, and emission 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 September 30, 2012, FES has posted collateral of $73 million. The Regulated Distribution segment has posted collateral of $21 million.

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

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3 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 table discloses the additional credit contingent contractual obligations as of September 30, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 397	$ 6	$ 42	$ 445
BB+/Ba1 Credit Ratings	$ 450	$ 6	$ 61	$ 517
Full impact of credit contingent contractual obligations	$ 671	$ 72	$ 76	$ 819

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of September 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 $40 million and $11 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

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

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

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility by December 31, 2013 on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, of 4% through December 31, 2012, 5% from January 1 through December 31, 2013 and, thereafter, a rate per annum equal to the then current Merrill Lynch High Yield 100 index, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

ENVIRONMENTAL MATTERS

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

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, 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 vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In 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. On July 27, 2012, ME filed a motion for summary judgment on plaintiff's remaining 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. On November 1, 2012, the other defendants and the plaintiffs filed motions for summary judgment regarding various claims. FirstEnergy believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued 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 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 and their opening appellate brief is due November 14, 2012. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

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

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received 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. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities 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 December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. The Court ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. 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. 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 approximately $975 million and other changes to FirstEnergy's operations may result.

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, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. 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. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. During the nine months ended September 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) 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. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated 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. The EHB dismissed these appeals on August 29, 2012, after a settlement in the form of a Consent Decree was entered by the Commonwealth Court of Pennsylvania on August 16, 2012, resolving the disputes concerning the Hatfield's Ferry Plant NPDES permit, including elimination of the TDS limit and deferring the lower sulphate limits until July 2018.

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 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 $150 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In 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. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. On August 14, 2012, a Consent Decree was entered by the Court resolving these claims. MP is currently seeking relief from the arsenic limits through a 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 proposed Consent Decree, if entered by the court, 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 proposed Consent Decree would also require payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. The Bruce Mansfield Plant 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 FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of September 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 $123 million (including $86 million applicable to JCP&L) have been accrued through September 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 September 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 SAMA analysis. On July 26, 2012, FENOC filed a motion for Summary Disposition on the remaining admitted contention on the SAMA analysis for Davis-Besse. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the longitudinal cracking of the Davis-Besse shield building discussed below. The intervenors supplemented their petition for a contention on the shield building on multiple occasions. The ASLB scheduled a November 5 and 6, 2012 oral argument to consider FENOC's motion for summary disposition, the intervenors request for a new contention on the Shield Building.

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. On July 9, 2012, the intervenors petitioned the ASLB for a new contention on the environmental impacts of temporary spent fuel storage by Davis-Besse due to the lack of a repository and the disposal of these wastes. 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. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

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. The NRC Staff began its 95002 inspection at the Perry plant on August 27, 2012. 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.

On September 17, 2012, FENOC announced a plan to expand used nuclear fuel storage capacity at its two unit Beaver Valley Power Station. Under the plan, above-ground, airtight steel and concrete canisters will be installed to provide cooling, through natural air circulation, to used fuel assemblies. Initial installation will consist of six canisters and up to 47 additional canisters will be added as needed. Construction of the fuel storage system is scheduled to begin in fall 2012, with completion planned for 2014. Certain costs incurred by FirstEnergy for this project are expected to be reimbursable by the DOE under a January 2012 settlement. Due to a change in NRC regulations, FirstEnergy will be required to independently fund the radiological decommissioning of its independent spent fuel storage facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term 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, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP will file a Petition for Allowance of Appeal with the Pennsylvania Supreme Court within 30 days. A ruling by the Supreme Court on whether it will hear the case is expected in the second quarter of 2013. 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 heard arguments on the appeal in September, 2012.

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 9, 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.

Storm Cost Contingency

In late October 2012, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Sandy. Approximately 2.3 million customers were affected by outages in New Jersey, Pennsylvania, West Virginia, Ohio and Maryland. Nearly 20,000 professionals, including employees from FirstEnergy's Utilities and outside contractors and utility workers have worked to restore service to customers who lost power following the devastating storm. As of November 7, 2012, more than 95% of customers in Pennsylvania, Ohio, West Virginia and Maryland who were affected by the storm had electric service restored. In New Jersey, where the storm damage was most severe, nearly 1.2 million customers were affected by the storm. As of November 7, 2012, 85% of affected customers in New Jersey have been restored. Storm costs are expected to exceed $500 million, of which approximately 95% is expected to be capitalized or deferred for future recovery from customers. Final storm costs will be determined during the fourth quarter of 2012.

Regulatory Matters	9 Months Ended Sep. 30, 2012

Regulated Operations [Abstract]

REGULATORY MATTERS

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 that are 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. 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 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. On December 22, 2011, the MDPSC 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.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted on September 13 and 14, 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards that the MDPSC approved on April 17, 2012, and which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. The panel's report has been referred to the MDPSC for action.

NEW JERSEY

JCP&L currently provides BGS for retail customers that do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates. The most recent BGS auction results, for supply that commenced on 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, 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. Due to Hurricane Sandy, JCP&L requested an extension and will file a base rate case using a historic 2011 test year by December 1, 2012.

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 consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. The NJBPU solicited written comments on the report from stakeholders to be submitted by September 20, 2012, and JCP&L submitted written comments on that date. The NJBPU has not specified the action that will 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. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing.

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at 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 provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in 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 RECs 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.

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. 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 by the PUCO and the subsequent appeal was dismissed by the Supreme Court of Ohio. 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. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period. Hearings were held the week of October 22, 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 were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of In-State All Renewable obligations that the auditor characterized as excessive. The PUCO has set this matter for hearing on February 19, 2013. 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. The Ohio companies are in the midst of a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks 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 EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 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. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies made a compliance filing on September 6, 2012, seeking finalization of their procurement and rate design plans, and the PPUC issued a Secretarial Letter on November 8, 2012 approving the compliance filing. The PPUC entered an order on September 27, 2012, disposing of the Petitions for Reconsideration or Clarification filed by the Pennsylvania Companies and other parties. The Pennsylvania Companies were granted an extension to file revised proposals on the retail market enhancements by November 14, 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's and PN's TSC riders. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which was denied on February 28, 2012, and ME and PN also filed 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 the amended complaint on September 15, 2011, to which ME and PN responded. On September 26, 2012, United States District Court Judge Gardner entered an order dismissing the PPUC's motion to dismiss without prejudice. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. On October 9, 2012, the Supreme Court denied that petition. Accordingly, ME and PN intend to 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 could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 1, 2012, a phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. A hearing on the level of the Pennsylvania Companies' respective Phase II energy efficiency targets as established by the PPUC was held on October 19, 2012. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator.

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 SMIP, 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 AE 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 EGSs; 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. On September 27, 2012, the PPUC issued a Secretarial Letter and an "RMI End State Proposal" discussion document. PPUC staff hosted a conference call on October 17, 2012, and a Tentative Order was entered by the PPUC on November 8, 2012, seeking comments, that are due within 30 days, regarding the end state of default service and related issues.

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. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

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 February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all alternative and RECs associated with the 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 on November 22, 2011, granting ownership of all RECs produced by the facilities to MP, and holding that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility formed under PURPA owns the RECs associated with that purchase. 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 filed complaints at FERC alleging the WVPSC order violated PURPA and requested that 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 order 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, which was denied by FERC on September 20, 2012. The City of 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. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated by September 1, 2012.

The WVPSC has proceedings for each West Virginia electric utility to establish reliability targets for distribution performance. The parties entered into a settlement in September 2012 resolving all issues and establishing performance targets with more stringent targets beginning in 2014. The settlement is under review by the WVPSC.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012.

The West Virginia ENEC fuel case was filed by MP and PE at the WVPSC in August 2012 with a projected over-recovery of approximately $66 million under current rates for the next year, January 1, 2013 through December 31, 2013. MP and PE proposed no change in overall rates on January 1, 2013; however, MP and PE proposed establishing a separate regulatory liability for the difference between the recommended 2013 ENEC rates and the current ENEC rates. This estimated $66 million liability would be used to offset the rate relief MP and PE will seek in a filing later this year to become effective with the completion of a proposed generation resource transaction, which MP and PE will propose to complete by mid-2013. Discovery in the ENEC proceeding is underway and a hearing is expected in December 2012.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE plan to file a Petition for Approval of a Generation Resource Transaction with the WVPSC in November 2012 that involves a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement what we believe to be a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make additional electricity and capacity purchases from the spot market which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to increase due to an increase in annual load growth of approximately 1.4%.

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. 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.

During September 2012, RFC performed a routine compliance audit of certain parts of FirstEnergy's bulk-power systems and generally found the audited systems and processes to be in full compliance with all the audited reliability standards.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" 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 LSEs 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. FirstEnergy's request for rehearing remains pending before FERC.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays (or usage based) and 50% postage stamp (or socialization) to be effective for RTEP projects approved by the PJM Board on and after the effective date of the compliance filing. The filing is pending before FERC. Filings to demonstrate compliance with the interregional cost allocation principles of the order must be submitted to FERC by April 2013.

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. Finally, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to loads in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI is considering whether to appeal FERC's ruling on the "legacy RTEP" issue. FirstEnergy has also appealed the issue of legacy RTEP to the Seventh Circuit Court of Appeals. Although there can be no assurance, success in the appeal could terminate the ATSI zone's responsibility for legacy RTEP charges.

ATSI's filings and requests for rehearing on certain of these matters, as well as the pleadings submitted by parties that oppose ATSI's position are currently pending before FERC. Finally, on August 22, 2012, FERC approved 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.

The 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 $16 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 may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings and appeals. These further proceedings can be divided into two classes: litigation related to the MISO's generic MVP cost allocation proposal; and litigation related to the MISO's "Schedule 39" tariff that purports to charge the MVP costs against ATSI.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of the FERC's orders that address the generic MVP tariffs 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 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 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. The hearings will start in April 2013.

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 LSEs 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. On September 10, 2012, PJM submitted the compliance filing. On October 17, 2012, FERC accepted the PJM compliance filing, resolving this matter.

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 had previously remanded one of those proceedings to FERC. In March 2010, the FERC ALJ 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 20, 2012, the California Parties appealed the FERC's decision back to the Ninth Circuit Court of Appeals. On July 19, 2012, the Ninth Circuit Court of Appeals issued an order declining to consolidate the appeal with other pending appeals regarding California refund claims, suspending briefing, and directing interested parties to intervene by August 31, 2012. AE Supply filed an intervention on August 28, 2012. On September 6, 2012, the Ninth Circuit issued an order granting AE Supply's intervention and continuing the suspension of the briefing schedule ordered on July 19, 2012. The timing of further action by the Ninth Circuit is unknown.

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, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this additional complaint. AE Supply filed a motion to dismiss this second complaint, which 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 20, 2012, the California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. In addition, on July 13, 2012, the California Attorney General requested rehearing of the June 13, 2012 order. On July 19, 2012, the Ninth Circuit consolidated the June 20, 2012 appeal with other pending appeals related to California refund claims, referred the case to the Circuit Mediator, and stayed the proceedings pending further order. On August 7, 2012, FERC rejected the California Attorney General's July 13, 2012 request for rehearing. On August 16, 2012, the California Attorney General appealed the August 7, 2012 order to the Ninth Circuit. On August 29, 2012, the Ninth Circuit consolidated the August 16, 2012 appeal with the aforementioned cases and continued the stay pending further order. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers officially canceled the project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, these companies requested authorization from FERC to recover these costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) from PJM customers over the next 5 years. Several parties have protested the request and a FERC decision is pending.

On September 20, 2012, FERC set for hearing formal challenges to the PATH formula rate annual updates submitted in June 2010 and June 2011. These challenges seek a disallowance of approximately $6.6 million in costs for the project. Settlement judge procedures are pending. FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

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, which 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. FirstEnergy submitted comments on August 10, 2012, and reply comments 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.

Fair Value Measurements (Details 6) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	$ 15,627	$ 15,716
Carrying Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	16,942	17,165
Fair Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	19,677	19,320
FES		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	3,085	2,799
FES | Carrying Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	4,133	3,675
FES | Fair Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	4,494	3,931
OE		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	1,157	1,155
OE | Carrying Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	1,157	1,157
OE | Fair Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	1,500	1,434
JCP&L		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	1,711	1,736
JCP&L | Carrying Value		

Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	1,753	1,777
JCP&L | Fair Value		
Fair value and related carrying amounts of long-term debt and other long-term obligations		
Long-term debt and other long-term obligations	$ 2,092	$ 2,080

Pensions and Other Postemployment Benefits (Details Textuals) (Qualified Pension Plan, USD $)	9 Months Ended Sep. 30, 2012
Qualified Pension Plan	
Defined Benefit Plan Disclosure [Line Items]	
Employer Contribution for qualified Plans	$ 600,000,000
Employer contributions for the remainder of the fiscal year	$ 0

Supplemental Guarantor Information	9 Months Ended Sep. 30, 2012
Supplemental Guarantor Information [Abstract]	
SUPPLEMENTAL GUARANTOR INFORMATION	

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 nine months ended September 30, 2012 and 2011, Consolidating Balance Sheets as of September 30, 2012 and December 31, 2011, and Consolidating Statements of Cash Flows for the nine months ended September 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 September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 1,523	$ 617	$ 395	$ (978)	$ 1,557
OPERATING EXPENSES:					
Fuel	—	248	55	—	303
Purchased power from affiliates	1,042	—	67	(978)	131
Purchased power from non-affiliates	499	—	—	—	499
Other operating expenses	130	79	122	12	343
Provision for depreciation	1	30	41	(1)	71
General taxes	20	10	5	—	35
Total operating expenses	1,692	367	290	(967)	1,382
OPERATING INCOME (LOSS)	(169)	250	105	(11)	175
OTHER INCOME (EXPENSE):					
Investment income	1	5	37	(5)	38

Miscellaneous income, including net income from equity investees	317	—	—	(316)	1
Interest expense — affiliates	(5)	(2)	(1)	5	(3)
Interest expense — other	(25)	(27)	(15)	16	(51)
Capitalized interest	—	1	8	—	9
Total other income (expense)	288	(23)	29	(300)	(6)
INCOME BEFORE INCOME TAXES	119	227	134	(311)	169
INCOME TAXES (BENEFITS)	18	(11)	59	2	68
NET INCOME	$ 101	$ 238	$ 75	$ (313)	$ 101
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 101	$ 238	$ 75	$ (313)	$ 101
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available for sale securities	(2)	—	(1)	1	(2)
Other comprehensive loss	(9)	(4)	(1)	5	(9)
Income tax benefits on other comprehensive loss	(3)	(2)	—	2	(3)
Other comprehensive loss, net of tax	(6)	(2)	(1)	3	(6)
COMPREHENSIVE INCOME	$ 95	$ 236	$ 74	$ (310)	$ 95

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,443	$ 1,795	$ 1,262	$ (2,971)	$ 4,529
OPERATING EXPENSES:					
Fuel	—	824	154	—	978

Purchased power from affiliates	3,163	—	189	(2,971)	381
Purchased power from non-affiliates	1,420	—	—	—	1,420
Other operating expenses	313	271	410	37	1,031
Provision for depreciation	3	90	114	(4)	203
General taxes	60	28	16	—	104
Total operating expenses	4,959	1,213	883	(2,938)	4,117
OPERATING INCOME (LOSS)	(516)	582	379	(33)	412
OTHER INCOME (EXPENSE):					
Investment income	2	14	49	(15)	50
Miscellaneous income, including net income from equity investees	854	19	—	(848)	25
Interest expense — affiliates	(14)	(5)	(3)	15	(7)
Interest expense — other	(72)	(79)	(36)	47	(140)
Capitalized interest	—	3	24	—	27
Total other income (expense)	770	(48)	34	(801)	(45)
INCOME BEFORE INCOME TAXES	254	534	413	(834)	367
INCOME TAXES (BENEFITS)	32	(19)	124	8	145
NET INCOME	$ 222	$ 553	$ 289	$ (842)	$ 222

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$ 222	$ 553	$ 289	$ (842)	$ 222
OTHER COMPREHENSIVE INCOME					
Pensions and OPEB prior service costs	(2)	(1)	—	1	(2)
Amortized loss on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available for sale securities	11	—	12	(12)	11
Other comprehensive income (loss)	3	(1)	12	(11)	3
Income taxes (benefits) on other comprehensive income (loss)	1	(1)	5	(4)	1
Other comprehensive income, net of tax	2	—	7	(7)	2
COMPREHENSIVE INCOME	$ 224	$ 553	$ 296	$ (849)	$ 224

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 1,445	$ 686	$ 371	$ (1,035)	$ 1,467
OPERATING EXPENSES:					
Fuel	6	323	57	—	386
Purchased power from affiliates	1,031	4	55	(1,035)	55
Purchased power from non-affiliates	330	(2)	—	—	328
Other operating expenses	162	94	122	12	390
Provision for depreciation	1	33	36	(1)	69
General taxes	19	9	3	—	31
Impairment of long-lived assets	—	2	—	—	2
Total operating expenses	1,549	463	273	(1,024)	1,261
OPERATING INCOME (LOSS)	(104)	223	98	(11)	206
OTHER INCOME (EXPENSE):					
Investment income	—	—	28	—	28
Miscellaneous income, including net income from equity investees	196	16	—	(203)	9
Interest expense — affiliates	—	(1)	(1)	—	(2)
Interest expense — other	(24)	(26)	(16)	15	(51)
Capitalized interest	—	3	5	—	8
Total other income (expense)	172	(8)	16	(188)	(8)
INCOME BEFORE INCOME TAXES	68	215	114	(199)	198
INCOME TAXES (BENEFITS)	(52)	83	45	2	78
NET INCOME	$ 120	$ 132	$ 69	$ (201)	$ 120
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 120	$ 132	$ 69	$ (201)	$ 120

OTHER COMPREHENSIVE LOSS					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available for sale securities	(22)	—	(22)	22	(22)
Other comprehensive loss	(28)	(4)	(22)	26	(28)
Income tax benefits on other comprehensive loss	(11)	(2)	(9)	11	(11)
Other comprehensive loss, net of tax	(17)	(2)	(13)	15	(17)
COMPREHENSIVE INCOME	$ 103	$ 130	$ 56	$ (186)	$ 103

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Nine Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,087	$ 1,964	$ 1,233	$ (3,133)	$ 4,151
OPERATING EXPENSES:					
Fuel	13	883	149	—	1,045
Purchased power from affiliates	3,118	15	189	(3,133)	189
Purchased power from non-affiliates	959	(5)	—	—	954
Other operating expenses	483	313	435	37	1,268
Provision for depreciation	3	96	112	(4)	207
General taxes	46	28	17	—	91
Impairment of long-lived assets	—	22	—	—	22
Total operating expenses	4,622	1,352	902	(3,100)	3,776
OPERATING INCOME (LOSS)	(535)	612	331	(33)	375
OTHER INCOME (EXPENSE):					
Investment income	1	1	48	—	50
Miscellaneous income, including net income from equity investees	570	18	—	(571)	17
Interest expense — affiliates	(1)	(2)	(2)	—	(5)
Interest expense — other	(72)	(82)	(49)	47	(156)
Capitalized interest	—	13	15	—	28

Total other income (expense)	498	(52)	12	(524)	(66)
INCOME (LOSS) BEFORE INCOME TAXES	(37)	560	343	(557)	309
INCOME TAXES (BENEFITS)	(231)	208	131	7	115
NET INCOME	$ 194	$ 352	$ 212	$ (564)	$ 194

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$ 194	$ 352	$ 212	$ (564)	$ 194
OTHER COMPREHENSIVE LOSS					
Pensions and OPEB prior service costs	(14)	(12)	—	12	(14)
Amortized gain on derivative hedges	4	—	—	—	4
Change in unrealized gain on available for sale securities	(7)	—	(7)	7	(7)
Other comprehensive loss	(17)	(12)	(7)	19	(17)
Income tax benefits on other comprehensive loss	(7)	(6)	(3)	9	(7)
Other comprehensive loss, net of tax	(10)	(6)	(4)	10	(10)
COMPREHENSIVE INCOME	$ 184	$ 346	$ 208	$ (554)	$ 184

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 3	$ —	$ —	$ 3
Receivables-					
Customers	485	—	—	—	485
Affiliated companies	362	410	238	(608)	402
Other	63	15	25	—	103
Notes receivable from affiliated companies	153	2,061	406	(2,182)	438
Materials and supplies, at average cost	66	257	210	—	533
Derivatives	209	—	—	—	209
Prepayments and other	85	24	27	1	137

	1,423	2,770	906	(2,789)	2,310
PROPERTY, PLANT AND EQUIPMENT:					
In service	89	5,730	6,204	(385)	11,638
Less — Accumulated provision for depreciation	31	1,888	2,578	(185)	4,312
	58	3,842	3,626	(200)	7,326
Construction work in progress	32	203	820	—	1,055
	90	4,045	4,446	(200)	8,381
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,286	—	1,286
Investment in affiliated companies	6,555	—	—	(6,555)	—
Other	5	11	—	—	16
	6,560	11	1,286	(6,555)	1,302
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	270	—	(270)	—
Customer intangibles	114	—	—	—	114
Goodwill	24	—	—	—	24
Property taxes	—	20	23	—	43
Unamortized sale and leaseback costs	—	—	—	111	111
Derivatives	78	—	—	—	78
Other	127	163	2	(111)	181
	343	453	25	(270)	551
	$ 8,416	$ 7,279	$ 6,663	$ (9,814)	$ 12,544
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 565	$ 529	$ (21)	$ 1,074
Short-term borrowings-					
Affiliated companies	2,048	135	—	(2,183)	—
Accounts payable-					
Affiliated companies	618	311	463	(605)	787
Other	82	92	—	—	174
Accrued taxes	49	19	19	(4)	83
Derivatives	153	—	—	—	153
Other	50	154	24	16	244
	3,001	1,276	1,035	(2,797)	2,515
CAPITALIZATION:					
Total equity	3,802	3,651	2,886	(6,537)	3,802
Long-term debt and other long-term obligations	1,482	1,976	845	(1,218)	3,085
	5,284	5,627	3,731	(7,755)	6,887
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	900	900
Accumulated deferred income taxes	39	—	624	(162)	501

Asset retirement obligations	—	29	921	—	950
Retirement benefits	35	148	—	—	183
Lease market valuation liability	—	87	—	—	87
Other	57	112	352	—	521
	131	376	1,897	738	3,142
	$ 8,416	$ 7,279	$ 6,663	$ (9,814)	$ 12,544

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

	FES	FGCO	NGC	Eliminations	Consolidated
	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 Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (971)	$ 683	$ 799	$ (10)	$ 501
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	317	243	—	560
Short-term borrowings, net	982	49	—	(1,028)	3
Redemptions and Repayments-					

Long-term debt	—	(169)	(87)	10	(246)
Short-term borrowings, net	—	—	(32)	32	—
Other	(1)	(6)	(2)	—	(9)
Net cash provided from financing activities	981	191	122	(986)	308
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(10)	(175)	(350)	—	(535)
Nuclear fuel	—	—	(207)	—	(207)
Proceeds from asset sales	—	17	—	—	17
Sales of investment securities held in trusts	—	—	1,167	—	1,167
Purchases of investment securities held in trusts	—	—	(1,194)	—	(1,194)
Loans to affiliated companies, net	1	(715)	(337)	996	(55)
Other	(1)	(5)	—	—	(6)
Net cash used for investing activities	(10)	(878)	(921)	996	(813)
Net change in cash and cash equivalents	—	(4)	—	—	(4)
Cash and cash equivalents at beginning of period	—	7	—	—	7
Cash and cash equivalents at end of period	$ —	$ 3	$ —	$ —	$ 3

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Nine Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (367)	$ 539	$ 374	$ (9)	$ 537
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	140	107	—	247
Short-term borrowings, net	750	59	25	(834)	—
Redemptions and Repayments-					
Long-term debt	(136)	(351)	(313)	9	(791)
Short-term borrowings, net	—	—	—	(12)	(12)
Other	(8)	(1)	(2)	1	(10)
Net cash provided from (used for) financing activities	606	(153)	(183)	(836)	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:					

Property additions	(8)	(143)	(257)	—	(408)
Nuclear fuel	—	—	(65)	—	(65)
Proceeds from asset sales	9	510	—	—	519
Sales of investment securities held in trusts	—	—	1,613	—	1,613
Purchases of investment securities held in trusts	—	—	(1,654)	—	(1,654)
Loans to affiliated companies, net	(228)	(732)	172	845	57
Other	(12)	(24)	—	—	(36)
Net cash used for investing activities	(239)	(389)	(191)	845	26
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

Segment Information	9 Months Ended Sep. 30, 2012
Segment Reporting [Abstract]	
SEGMENT INFORMATION	**SEGMENT INFORMATION**

During 2012, FirstEnergy completed the integration of AE into its IT business networks and financial systems. An important element of this system integration was the capability of modifying 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 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 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 Allegheny 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 facilities owned and operated by certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and transmission companies (ATSI, TrAIL and PATH). Its revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. These revenues are derived from providing transmission services pursuant to the PJM Open Access Transmission Tariff to electric energy providers, power marketers and revenue from operating the FirstEnergy transmission facilities. Its results reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment controls approximately 17,000 MWs of capacity, excluding approximately 2,700 MWs from unregulated plants recently deactivated or planned to be deactivated (see Note 9, 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)			
September 30, 2012						
External revenues	$ 2,438	$ 187	$ 1,719	$ (30)	$ (3)	$ 4,311
Internal revenues	—	—	210	—	(210)	—
Total revenues	2,438	187	1,929	(30)	(213)	4,311
Depreciation and amortization	202	28	105	8	—	343
Investment income	20	—	36	(1)	(16)	39
Net interest charges	132	22	62	(4)	—	212
Income taxes	168	35	76	(9)	39	309
Net income*	286	59	129	(11)	(38)	425
Total assets	26,122	4,519	16,846	1,251	—	48,738
Total goodwill	5,025	526	893	—	—	6,444
Property additions	308	47	412	8	—	775
September 30, 2011						
External revenues	$ 2,864	$ 181	$ 1,714	$ (40)	$ (12)	$ 4,707
Internal revenues	1	—	315	—	(304)	12
Total revenues	2,865	181	2,029	(40)	(316)	4,719
Depreciation and amortization	273	31	110	5	—	419
Investment income	28	—	28	—	(8)	48
Net interest charges	133	23	73	21	—	250
Income taxes	164	32	142	(23)	10	325
Net income	280	56	242	(40)	(8)	530
Total assets	26,802	4,246	16,809	816	—	48,673
Total goodwill	5,025	526	877	—	—	6,428
Property additions	234	80	186	—	—	500
Nine Months Ended						
September 30, 2012						
External revenues	$ 6,857	$ 557	$ 4,942	$ (78)	$ (22)	$ 12,256
Internal revenues	—	—	686	—	(684)	2
Total revenues	6,857	557	5,628	(78)	(706)	12,258

Depreciation and amortization	636	89	307	25	—	1,057
Investment income	62	1	48	(1)	(47)	63
Net interest charges	396	68	175	57	—	696
Income taxes	355	101	173	(49)	78	658
Net income*	603	171	295	(82)	(68)	919
Total assets	26,122	4,519	16,846	1,251	—	48,738
Total goodwill	5,025	526	893	—	—	6,444
Property additions	751	169	715	51	—	1,686
September 30, 2011						
External revenues	$ 7,496	$ 476	$ 4,450	$ (93)	$ (30)	$ 12,299
Internal revenues	1	—	976	—	(921)	56
Total revenues	7,497	476	5,426	(93)	(951)	12,355
Depreciation and amortization	746	81	307	19	—	1,153
Investment income	76	—	49	1	(26)	100
Net interest charges	389	64	195	60	—	708
Income taxes	322	79	163	(53)	39	550
Net income	547	136	278	(145)	(46)	770
Total assets	26,802	4,246	16,809	816	—	48,673
Total goodwill	5,025	526	877	—	—	6,428
Property additions	615	250	543	56	—	1,464

* Regulated Distribution net income for the three and nine months ended September 30, 2012, include adjustments of $21.8 million and $15.1 million, respectively, from capitalizing various construction activities of the Allegheny Utilities that were previously expensed. The effect of these adjustments was not material to the current or previous periods.

Consolidated Statements of Income and Comprehensive Income (Unaudited) (FirstEnergy Solutions Corp.) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
REVENUES:				
Electric sales	$ 1,687	$ 1,678	$ 4,844	$ 4,389
Total revenues	2,624	3,041	7,414	7,966
OPERATING EXPENSES:				
Fuel	636	632	1,833	1,720
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME (LOSS)	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Investment income	39	48	63	100
Interest expense	(230)	(267)	(750)	(763)
Capitalized interest	18	17	54	55
Total other income (expense)	(173)	(202)	(633)	(608)
INCOME BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES (BENEFITS)	309	325	658	550
NET INCOME	425	530	919	770
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	425	530	919	770
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(47)	(48)	(148)	(44)
Amortized gain (loss) on derivative hedges	0	2	1	13
Change in unrealized gain on available-for-sale securities	1	(26)	13	(7)
Other comprehensive income (loss)	(46)	(72)	(134)	(38)
Income taxes (benefits) on other comprehensive income (loss)	(24)	(26)	(75)	(12)
Other comprehensive income (loss), net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
FES				
REVENUES:				
Other	63	73	180	229
Total revenues	1,557	1,467	4,529	4,151
OPERATING EXPENSES:				
Fuel	303	386	978	1,045
Other operating expenses	343	390	1,031	1,268

Provision for depreciation	71	69	203	207
General taxes	35	31	104	91
Impairment of long-lived assets	0	2	0	22
Total operating expenses	1,382	1,261	4,117	3,776
OPERATING INCOME (LOSS)	175	206	412	375
OTHER INCOME (EXPENSE):				
Investment income	38	28	50	50
Miscellaneous income	1	9	25	17
Capitalized interest	9	8	27	28
Total other income (expense)	(6)	(8)	(45)	(66)
INCOME BEFORE INCOME TAXES	169	198	367	309
INCOME TAXES (BENEFITS)	68	78	145	115
NET INCOME	101	120	222	194
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	101	120	222	194
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(5)	(5)	(2)	(14)
Amortized gain (loss) on derivative hedges	(2)	(1)	(6)	4
Change in unrealized gain on available-for-sale securities	(2)	(22)	11	(7)
Other comprehensive income (loss)	(9)	(28)	3	(17)
Income taxes (benefits) on other comprehensive income (loss)	(3)	(11)	1	(7)
Other comprehensive income (loss), net of tax	(6)	(17)	2	(10)
COMPREHENSIVE INCOME	95	103	224	184
FES | Affiliates				
REVENUES:				
Electric sales	155	143	385	574
OPERATING EXPENSES:				
Purchased power	131	55	381	189
OTHER INCOME (EXPENSE):				
Interest expense	(3)	(2)	(7)	(5)
FES | Non-Affiliates				
REVENUES:				
Electric sales	1,339	1,251	3,964	3,348
OPERATING EXPENSES:				
Purchased power	499	328	1,420	954
OTHER INCOME (EXPENSE):				
Interest expense	$ (51)	$ (51)	$ (140)	$ (156)

Significant Accounting Policies (Policies)	9 Months Ended Sep. 30, 2012
Significant Accounting Policies [Abstract]	
Goodwill, Policy	Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, a likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying amount. If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing of goodwill assigned to its reporting units is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify potential goodwill impairment and measure the amount of goodwill impaired to be recognized, if any.
Earnings Per Share, Policy	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.
Pension and Other Postretirement Plans, Policy	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 pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method.
Consolidation, Variable Interest Entity, Policy	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

Segment Information (Tables)	9 Months Ended Sep. 30, 2012

Segment Reporting [Abstract]

Segment Financial Information

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/ Corporate	Reconciling Adjustments	Consolidated
			(In millions)			
September 30, 2012						
External revenues	$ 2,438	$ 187	$ 1,719	$ (30)	$ (3)	$ 4,311
Internal revenues	—	—	210	—	(210)	—
Total revenues	2,438	187	1,929	(30)	(213)	4,311
Depreciation and amortization	202	28	105	8	—	343
Investment income	20	—	36	(1)	(16)	39
Net interest charges	132	22	62	(4)	—	212
Income taxes	168	35	76	(9)	39	309
Net income*	286	59	129	(11)	(38)	425
Total assets	26,122	4,519	16,846	1,251	—	48,738
Total goodwill	5,025	526	893	—	—	6,444
Property additions	308	47	412	8	—	775
September 30, 2011						
External revenues	$ 2,864	$ 181	$ 1,714	$ (40)	$ (12)	$ 4,707
Internal revenues	1	—	315	—	(304)	12
Total revenues	2,865	181	2,029	(40)	(316)	4,719
Depreciation and amortization	273	31	110	5	—	419
Investment income	28	—	28	—	(8)	48
Net interest charges	133	23	73	21	—	250
Income taxes	164	32	142	(23)	10	325
Net income	280	56	242	(40)	(8)	530
Total assets	26,802	4,246	16,809	816	—	48,673
Total goodwill	5,025	526	877	—	—	6,428
Property additions	234	80	186	—	—	500
Nine Months Ended						
September 30, 2012						

External revenues	$ 6,857	$ 557	$ 4,942	$ (78)	$ (22)	$ 12,256
Internal revenues	—	—	686	—	(684)	2
Total revenues	6,857	557	5,628	(78)	(706)	12,258
Depreciation and amortization	636	89	307	25	—	1,057
Investment income	62	1	48	(1)	(47)	63
Net interest charges	396	68	175	57	—	696
Income taxes	355	101	173	(49)	78	658
Net income*	603	171	295	(82)	(68)	919
Total assets	26,122	4,519	16,846	1,251	—	48,738
Total goodwill	5,025	526	893	—	—	6,444
Property additions	751	169	715	51	—	1,686
September 30, 2011						
External revenues	$ 7,496	$ 476	$ 4,450	$ (93)	$ (30)	$ 12,299
Internal revenues	1	—	976	—	(921)	56
Total revenues	7,497	476	5,426	(93)	(951)	12,355
Depreciation and amortization	746	81	307	19	—	1,153
Investment income	76	—	49	1	(26)	100
Net interest charges	389	64	195	60	—	708
Income taxes	322	79	163	(53)	39	550
Net income	547	136	278	(145)	(46)	770
Total assets	26,802	4,246	16,809	816	—	48,673
Total goodwill	5,025	526	877	—	—	6,428
Property additions	615	250	543	56	—	1,464

Fair Value Measurements (Details 3) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Debt Securities		
Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities		
Cost Basis	$ 1,529 [1]	$ 1,980 [2]
Unrealized Gains	37 [1]	25 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	1,566 [1]	2,005 [2]
Equity securities		
Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities		
Cost Basis	320 [1]	222 [2]
Unrealized Gains	46 [1]	36 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	366 [1]	258 [2]
FES | Debt Securities		
Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities		
Cost Basis	500 [1]	1,012 [2]
Unrealized Gains	8 [1]	13 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	508 [1]	1,025 [2]
FES | Equity securities		
Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities		
Cost Basis	295 [1]	104 [2]
Unrealized Gains	38 [1]	20 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	333 [1]	124 [2]
OE | Debt Securities		
Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities		
Cost Basis	137 [1]	134 [2]
Unrealized Gains	0 [1]	0 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	137 [1]	134 [2]
JCP&L | Debt Securities		

Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities

Cost Basis	364 [1]	356 [2]
Unrealized Gains	13 [1]	7 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	377 [1]	363 [2]
JCP&L | Equity securities		
Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities		
Cost Basis	0 [1]	27 [2]
Unrealized Gains	0 [1]	3 [2]
Unrealized Losses	0 [1]	0 [2]
Fair Value	$ 0 [1]	$ 30 [2]

[1] Excludes short-term cash investments: FE Consolidated - $596 million; FES - $443 million; OE - $3 million; JCP&L - $51 million

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

Consolidated Statements of Income (Unaudited) (FirstEnergy Corp.) (USD $) In Millions, except Per Share data, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
REVENUES:				
Electric utilities	$ 2,624	$ 3,041	$ 7,414	$ 7,966
Unregulated businesses	1,687	1,678	4,844	4,389
Total revenues	4,311 [1]	4,719 [1]	12,258 [1]	12,355 [1]
OPERATING EXPENSES:				
Fuel	636	632	1,833	1,720
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
Amortization of regulatory assets, net	61	122	198	344
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME (LOSS)	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Investment income	39	48	63	100
Interest expense	(230)	(267)	(750)	(763)
Capitalized interest	18	17	54	55
Total other income (expense)	(173)	(202)	(633)	(608)
INCOME BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES (BENEFITS)	309	325	658	550
NET INCOME	425	530	919	770
Income (loss) attributable to noncontrolling interest	0	(2)	1	(17)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 425	$ 532	$ 918	$ 787
EARNINGS PER SHARE OF COMMON STOCK:				
Basic, in dollars per share	$ 1.02	$ 1.27	$ 2.20	$ 2.01
Diluted, in dollars per share	$ 1.01	$ 1.27	$ 2.19	$ 2.00
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic, in shares	417	418	418	392
Diluted, in shares	419	420	419	394
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.10	$ 1.10	$ 1.65	$ 1.65

[1] Includes excise tax collections of $123 million and $137 million in the three months ended September 30, 2012 and 2011, respectively, and $351 million and $371 million in the nine months ended September 30, 2012 and 2011, respectively.

Pensions and Other Postemployment Benefits (Details) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Pensions				
Components of Net Periodic Benefit Costs (Credits)				
Service cost	$ 40	$ 34	$ 120	$ 97
Interest cost	97	96	291	276
Expected return on plan assets	(121)	(115)	(363)	(332)
Amortization of prior service cost	3	4	9	12
Other adjustments (settlements, curtailments, etc)			0	7
Net periodic costs (credits)	19	19	57	60
OPEB				
Components of Net Periodic Benefit Costs (Credits)				
Service cost	3	3	9	9
Interest cost	12	12	36	35
Expected return on plan assets	(9)	(10)	(27)	(30)
Amortization of prior service cost	(51)	(51)	(153)	(150)
Other adjustments (settlements, curtailments, etc)			0	0
Net periodic costs (credits)	$ (45)	$ (46)	$ (135)	$ (136)

Consolidated Balance Sheets (Unaudited) (FirstEnergy Corp.) (Parenthetical) (USD $) In Millions, except Share data, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Common stockholders' equity-		
Common stock, par value (in dollars per share)	$ 0.1	$ 0.1
Common stock, shares authorized	490,000,000	490,000,000
Common stock, shares outstanding	418,216,437	418,216,437
Customer [Member]		
Receivables-		
Allowance for uncollectible accounts	$ 43	$ 37
Other [Member]		
Receivables-		
Allowance for uncollectible accounts	$ 2	$ 3

Derivative Instruments (Details 1)	Sep. 30, 2012 MWh
Power Contracts	
Volume of First Energy's outstanding derivative transactions	
Purchases, in ones	33,000,000
Sales, in ones	38,000,000
Net, in ones	(5,000,000)
FTRs	
Volume of First Energy's outstanding derivative transactions	
Purchases, in ones	67,000,000
Sales, in ones	0
Net, in ones	67,000,000
NUGs	
Volume of First Energy's outstanding derivative transactions	
Purchases, in ones	16,000,000
Sales, in ones	0
Net, in ones	16,000,000
LCAPP	
Volume of First Energy's outstanding derivative transactions	
Volume of Derivatives, Purchases, in ones	408,000,000
Volume of Derivatives, Sales, in ones	0
Volume of Derivatives, Net, in ones	408,000,000
Natural Gas Futures	
Volume of First Energy's outstanding derivative transactions	
Purchases, in ones	16,000,000
Sales, in ones	0
Net, in ones	16,000,000

Variable Interest Entities (Tables)	9 Months Ended Sep. 30, 2012
Variable Interest Entities [Abstract]	
Net exposure to loss based upon the casualty value provisions	The following table discloses each company's net exposure to loss based upon the casualty value provisions as of September 30, 2012:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(In millions)	
FES	$ 1,339	$ 1,123	$ 216
OE	551	390	161
Other FE subsidiaries	561	326	235

(1) The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.4 billion.

Commitments, Guarantees and Contingencies (Details) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	$ 819
Split Rating (One rating agency's rating below investment grade)	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	445
BB Plus/BA1 Credit Ratings	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	517
FES	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	671
FES | Split Rating (One rating agency's rating below investment grade)	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	397
FES | BB Plus/BA1 Credit Ratings	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	450
AE Supply	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	72
AE Supply | Split Rating (One rating agency's rating below investment grade)	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	6
AE Supply | BB Plus/BA1 Credit Ratings	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	6
Utilities	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	76
Utilities | Split Rating (One rating agency's rating below investment grade)	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	42
Utilities | BB Plus/BA1 Credit Ratings	
Guarantor Obligations [Line Items]	
Maximum exposure under collateral provisions	$ 61

Earnings Per Share	9 Months Ended Sep. 30, 2012
Earnings Per Share [Abstract]	
EARNINGS PER SHARE	**EARNINGS PER SHARE**

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 September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
	(In millions, except per share amounts)			
Weighted average number of basic shares outstanding	417	418	418	392
Assumed exercise of dilutive stock options and awards[1]	2	2	1	2
Weighted average number of diluted shares outstanding	419	420	419	394
Earnings Available to FirstEnergy Corp.	$ 425	$ 532	$ 918	$ 787
Basic earnings per share of common stock	$ 1.02	$ 1.27	$ 2.20	$ 2.01
Diluted earnings per share of common stock	$ 1.01	$ 1.27	$ 2.19	$ 2.00

[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 nine months ended September 30, 2012 and 2011.

Fair Value Measurements (Tables)	9 Months Ended Sep. 30, 2012

Fair Value of Financial Instruments [Line Items]

Assets and liabilities measured on recurring basis

FirstEnergy

Recurring Fair Value Measurements	September 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	$ —	$ 1,012	$ —	1,012	$ —	$ 1,544	$ —	$ 1,544
Derivative assets - commodity contracts	3	257	—	260	—	264	—	264
Derivative assets - FTRs	—	—	7	7	—	—	1	1
Derivative assets - NUG contracts[(1)]	—	—	18	18	—	—	56	56
Equity securities[(2)]	367	—	—	367	259	—	—	259
Foreign government debt securities	—	60	—	60	—	3	—	3
U.S. government debt securities	—	184	—	184	—	148	—	148
U.S. state debt securities	—	314	—	314	—	314	—	314
Other[(3)]	124	562	—	686	49	225	—	274
Total assets	494	2,389	25	2,908	308	2,498	57	2,863
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(247)	—	(247)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(23)	(23)
Derivative liabilities - NUG contracts[(1)]	—	—	(300)	(300)	—	—	(349)	(349)
Derivative liabilities - LCAPP contracts[(1)]	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	(177)	(453)	(630)	—	(247)	(372)	(619)
Net assets (liabilities)[(4)]	$ 494	$ 2,212	$ (428)	$ 2,278	$ 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 $43 million and $(52) million as of September 30, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Reconciliation of changes in the fair value roll forward of level 3 measurements of NUG contracts

The following table provides a reconciliation of changes in the fair value of NUG and LCAPP contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 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
					(in millions)				
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)	(39)	(144)	(183)	—	3	3	1	(4)	(3)
Purchases	—	—	—	—	(145)	(145)	12	(10)	2
Issues	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	—	193	193	—	—	—	(7)	26	19
Transfers in (out) of Level 3	—	—	—	—	—	—	—	—	—

September 30, 2012 Balance	$ 18	$ (300)	$ (282)	$ —	$ (142)	$ (142)	$ 7	$ (11)	$ (4)

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

Quantitative information for level 3 valuation

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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (4)	Model	RTO auction clearing prices	($3.80) to $6.40	$ 0.50	Dollars/MWH
NUG Contracts	$ (282)	Model	Generation Electricity regional prices	700 to 6,748,000 $43.40 to $57.30	3,211,000 $51.90	MWH Dollars/MWH
LCAPP Contracts	$ (142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

Amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities

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

	September 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								
FirstEnergy	$ 1,529	$ 37	$ —	$ 1,566	$ 1,980	$ 25	$ —	$ 2,005
FES	500	8	—	508	1,012	13	—	1,025
OE	137	—	—	137	134	—	—	134
JCP&L	364	13	—	377	356	7	—	363
Equity securities								
FirstEnergy	$ 320	$ 46	$ —	$ 366	$ 222	$ 36	$ —	$ 258
FES	295	38	—	333	104	20	—	124
JCP&L	—	—	—	—	27	3	—	30

(1) Excludes short-term cash investments: FE Consolidated - $596 million; FES - $443 million; OE - $3 million; JCP&L - $51 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

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 nine months ended September 30, 2012 and 2011 were as follows:

Three Months Ended

September 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$ 1,751	$ 81	$ (32)	$ 18
FES	1,059	60	(23)	10
OE	—	—	—	1
JCP&L	211	6	(2)	4

September 30, 2011	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$ 1,974	$ 98	$ (38)	$ 20
FES	1,100	52	(19)	9
OE	134	7	(1)	1
JCP&L	234	11	(4)	5

Nine Months Ended

September 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$ 2,133	$ 118	$ (67)	$ 51

FES	1,167	85	(48)	27
OE	57	—	—	2
JCP&L	376	8	(4)	11

September 30, 2011	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 3,678	$ 220	$ (83)	$ 72
FES	1,613	74	(42)	41
OE	154	7	(1)	3
JCP&L	610	37	(10)	13

Amortized cost basis, unrealized gains and losses, and approximate fair values of investments in 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 September 30, 2012 and December 31, 2011:

	September 30, 2012			December 31, 2011		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt Securities						
FirstEnergy	$ 210	$ 58	$ 268	$ 402	$ 50	$ 452
OE	148	33	181	163	21	184

Fair value and related carrying amounts of long-term debt and other long-term obligations

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 September 30, 2012 and December 31, 2011:

	September 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
FirstEnergy	$ 16,942	$ 19,677	$ 17,165	$ 19,320
FES	4,133	4,494	3,675	3,931
OE	1,157	1,500	1,157	1,434
JCP&L	1,753	2,092	1,777	2,080

FES

Fair Value of Financial Instruments [Line Items]

Assets and liabilities measured on recurring basis

FES

Recurring Fair Value Measurements	September 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	$ —	$ 437	$ —	$ 437	$ —	$ 1,010	$ —	$ 1,010
Derivative assets - commodity contracts	3	252	—	255	—	248	—	248
Derivative assets - FTRs	—	—	5	5	—	—	1	1
Equity securities(1)	334	—	—	334	124	—	—	124
Foreign government debt securities	—	50	—	50	—	3	—	3
U.S. government debt securities	—	21	—	21	—	7	—	7
U.S. state debt securities	—	—	—	—	—	5	—	5
Other(2)	—	396	—	396	—	132	—	132
Total assets	337	1,156	5	1,498	124	1,405	1	1,530
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(234)	—	(234)
Derivative liabilities - FTRs	—	—	(7)	(7)	—	—	(7)	(7)
Total liabilities	—	(177)	(7)	(184)	—	(234)	(7)	(241)
Net assets (liabilities)(3)	$ 337	$ 979	$ (2)	$ 1,314	$ 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 $47 million and $(58) million as of September 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.

Reconciliation of changes in the fair value roll forward of level 3 measurements of NUG contracts

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 September 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	(2)	(1)
Purchases	8	(7)	1
Issues	—	—	—
Sales	—	—	—
Settlements	(5)	9	4
Transfers in (out) of Level 3	—	—	—
September 30, 2012 Balance	$ 5	$ (7)	$ (2)

Quantitative information for level 3 valuation

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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (2)	Model	RTO auction clearing prices	($3.80) to $6.40	$0.30	Dollars/ MWH

OE

Fair Value of Financial Instruments [Line Items]

Assets and liabilities measured on recurring basis

OE

Recurring Fair Value Measurements	September 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 and $1 million as of September 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

Fair Value of Financial Instruments [Line Items]

Assets and liabilities measured on recurring basis

JCP&L

Recurring Fair Value Measurements	September 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	$ —	$ 139	$ —	$ 139	$ —	$ 144	$ —	$ 144
Derivative assets - NUG contracts[(1)]	—	—	1	1	—	—	4	4
Equity securities[(2)]	—	—	—	—	30	—	—	30

Foreign government debt securities	—	2	—	2	—	—	—	—
U.S. government debt securities	—	8	—	8	—	2	—	2
U.S. state debt securities	—	230	—	230	—	219	—	219
Other[3]	—	48	—	48	—	15	—	15
Total assets	—	427	1	428	30	380	4	414
Liabilities								
Derivative liabilities - NUG contracts[1]	—	—	(125)	(125)	—	—	(147)	(147)
Derivative liabilities - LCAPP contracts[1]	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	—	(267)	(267)	—	—	(147)	(147)
Net assets (liabilities)[4]	$ —	$ 427	$ (266)	$ 161	$ 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 $1 million and $2 million as of September 30, 2012 and December 31, 2011 of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Reconciliation of changes in the fair value roll forward of level 3 measurements of NUG contracts

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 September 30, 2012 and December 31, 2011:

	NUG Contracts[1]			LCAPP Contracts[1]		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(in millions)					
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)	(3)	(17)	(20)	—	3	3
Purchases	—	—	—	—	(145)	(145)
Issues	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	39	39	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
September 30, 2012 Balance	$ 1	$ (125)	$(124)	$ —	$ (142)	$(142)

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

Quantitative information for level 3 valuation

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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
NUG Contracts	$ (124)	Model	Generation Electricity regional prices	95,000 to 1,324,000 $45.50 to $59.50	405,000 $54.10	MWH Dollars/ MWH
LCAPP Contracts	$ (142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

Income Taxes	9 Months Ended Sep. 30, 2012
Income Tax Disclosure [Abstract]	
INCOME TAXES	**INCOME TAXES** FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Significant judgment is required in determining FirstEnergy's income taxes and in evaluating tax positions taken or expected to be taken on its tax returns. 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 nine months ended September 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 Allegheny 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 nine 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 first nine months of 2011. There were no other material changes to FirstEnergy's unrecognized income tax benefits during the first nine months of 2012 or 2011. As of September 30, 2012, it is reasonably possible that approximately $40 million of unrecognized income tax benefits may be resolved within the next twelve months, of which approximately $6 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 nine 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 nine months of 2011. During the first nine 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 September 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 nine months of 2011. FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2011) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2009-2011, and additionally 2001 and 2008 for Pennsylvania. 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 2009-2011. State tax returns for tax years 2009 through 2011 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.

Supplemental Guarantor Information (Details 1) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011	Sep. 30, 2011	Dec. 31, 2010
CURRENT ASSETS:				
Cash and cash equivalents	$ 150	$ 202	$ 291	$ 1,019
Receivables-				
Customers	1,604	1,525		
Other	227	269		
Materials and supplies, at average cost	875	811		
Derivatives	212	235		
Prepayments and other	190	122		
Total current assets	3,709	3,355		
PROPERTY, PLANT AND EQUIPMENT:				
In service	41,756	40,122		
Less - Accumulated provision for depreciation	12,434	11,839		
Property, plant and equipment in service net of accumulated provision for depreciation	29,322	28,283		
Construction work in progress	2,119	2,054		
Total net property, plant and equipment	31,441	30,337		
INVESTMENTS:				
Nuclear plant decommissioning trusts	2,203	2,112		
Other	1,038	1,008		
Total other property and investments	3,451	3,522		
DEFERRED CHARGES AND OTHER ASSETS:				
Goodwill	6,444	6,441	6,428	
Other	1,580	1,641		
Total deferred charges and other assets	10,137	10,112		
Total assets	48,738	47,326	48,673	
CURRENT LIABILITIES:				
Currently payable long-term debt	1,473	1,621		
Short-term borrowings-				
Affiliated companies	1,604	0		
Accounts payable-				
Accrued Taxes	508	558		
Derivatives	155	218		
Other	942	900		
Total current liabilities	5,920	4,855		
CAPITALIZATION:				
Total equity	13,433	13,280		
Long-term debt and other long-term obligations	15,627	15,716		
Total capitalization	29,076	29,015		
NONCURRENT LIABILITIES:				

Deferred gain on sale and leaseback transaction	900	925		
Accumulated deferred income taxes	6,543	5,670		
Asset retirement obligations	1,574	1,497		
Retirement benefits	2,271	2,823		
Other	1,904	2,072		
Total noncurrent liabilities	13,742	13,456		
Total liabilities and capitalization	48,738	47,326		
FES Corp				
CURRENT ASSETS:				
Cash and cash equivalents	0	0	0	0
Receivables-				
Customers	485	424		
Affiliated companies	362	476		
Other	63	28		
Notes receivable from affiliated companies	153	155		
Materials and supplies, at average cost	66	60		
Derivatives	209	219		
Prepayments and other	85	11		
Total current assets	1,423	1,373		
PROPERTY, PLANT AND EQUIPMENT:				
In service	89	84		
Less - Accumulated provision for depreciation	31	28		
Property, plant and equipment in service net of accumulated provision for depreciation	58	56		
Construction work in progress	32	29		
Total net property, plant and equipment	90	85		
INVESTMENTS:				
Nuclear plant decommissioning trusts	0	0		
Investment in affiliated companies	6,555	5,700		
Other	5	0		
Total other property and investments	6,560	5,700		
DEFERRED CHARGES AND OTHER ASSETS:				
Accumulated deferred income tax benefits	0	10		
Customer intangibles	114	123		
Goodwill	24	24		
Property taxes	0	0		
Unamortized sale and leaseback costs	0	0		
Derivatives	78	79		
Other	127	89		
Total deferred charges and other assets	343	325		
Total assets	8,416	7,483		
CURRENT LIABILITIES:				
Currently payable long-term debt	1	1		
Accounts payable-				

Affiliated companies	618	777		
Other	82	99		
Accrued Taxes	49	84		
Derivatives	153	189		
Other	50	62		
Total current liabilities	3,001	2,277		
CAPITALIZATION:				
Total equity	3,802	3,577		
Long-term debt and other long-term obligations	1,482	1,483		
Total capitalization	5,284	5,060		
NONCURRENT LIABILITIES:				
Deferred gain on sale and leaseback transaction	0	0		
Accumulated deferred income taxes	39	12		
Asset retirement obligations	0	0		
Retirement benefits	35	56		
Lease market valuation liability	0	0		
Other	57	78		
Total noncurrent liabilities	131	146		
Total liabilities and capitalization	8,416	7,483		
FGCO				
CURRENT ASSETS:				
Cash and cash equivalents	3	7	6	9
Receivables-				
Customers	0	0		
Affiliated companies	410	643		
Other	15	20		
Notes receivable from affiliated companies	2,061	1,346		
Materials and supplies, at average cost	257	232		
Derivatives	0	0		
Prepayments and other	24	26		
Total current assets	2,770	2,274		
PROPERTY, PLANT AND EQUIPMENT:				
In service	5,730	5,573		
Less - Accumulated provision for depreciation	1,888	1,813		
Property, plant and equipment in service net of accumulated provision for depreciation	3,842	3,760		
Construction work in progress	203	195		
Total net property, plant and equipment	4,045	3,955		
INVESTMENTS:				
Nuclear plant decommissioning trusts	0	0		
Investment in affiliated companies	0	0		
Other	11	7		
Total other property and investments	11	7		
DEFERRED CHARGES AND OTHER ASSETS:				

Accumulated deferred income tax benefits	270	307		
Customer intangibles	0	0		
Goodwill	0	0		
Property taxes	20	20		
Unamortized sale and leaseback costs	0	5		
Derivatives	0	0		
Other	163	99		
Total deferred charges and other assets	453	431		
Total assets	7,279	6,667		
CURRENT LIABILITIES:				
Currently payable long-term debt	565	411		
Accounts payable-				
Affiliated companies	311	228		
Other	92	121		
Accrued Taxes	19	42		
Derivatives	0	0		
Other	154	141		
Total current liabilities	1,276	1,032		
CAPITALIZATION:				
Total equity	3,651	3,097		
Long-term debt and other long-term obligations	1,976	1,905		
Total capitalization	5,627	5,002		
NONCURRENT LIABILITIES:				
Deferred gain on sale and leaseback transaction	0	0		
Accumulated deferred income taxes	0	0		
Asset retirement obligations	29	28		
Retirement benefits	148	300		
Lease market valuation liability	87	171		
Other	112	134		
Total noncurrent liabilities	376	633		
Total liabilities and capitalization	7,279	6,667		
Nuclear Generation Corp				
CURRENT ASSETS:				
Cash and cash equivalents	0	0	0	0
Receivables-				
Customers	0	0		
Affiliated companies	238	262		
Other	25	13		
Notes receivable from affiliated companies	406	69		
Materials and supplies, at average cost	210	200		
Derivatives	0	0		
Prepayments and other	27	1		
Total current assets	906	545		
PROPERTY, PLANT AND EQUIPMENT:				

In service	6,204	5,711
Less - Accumulated provision for depreciation	2,578	2,449
Property, plant and equipment in service net of accumulated provision for depreciation	3,626	3,262
Construction work in progress	820	790
Total net property, plant and equipment	4,446	4,052
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,286	1,223
Investment in affiliated companies	0	0
Other	0	0
Total other property and investments	1,286	1,223
DEFERRED CHARGES AND OTHER ASSETS:		
Accumulated deferred income tax benefits	0	0
Customer intangibles	0	0
Goodwill	0	0
Property taxes	23	23
Unamortized sale and leaseback costs	0	0
Derivatives	0	0
Other	2	3
Total deferred charges and other assets	25	26
Total assets	6,663	5,846
CURRENT LIABILITIES:		
Currently payable long-term debt	529	513
Accounts payable-		
Affiliated companies	463	211
Other	0	0
Accrued Taxes	19	110
Derivatives	0	0
Other	24	16
Total current liabilities	1,035	882
CAPITALIZATION:		
Total equity	2,886	2,587
Long-term debt and other long-term obligations	845	641
Total capitalization	3,731	3,228
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	0	0
Accumulated deferred income taxes	624	510
Asset retirement obligations	921	876
Retirement benefits	0	0
Lease market valuation liability	0	0
Other	352	350
Total noncurrent liabilities	1,897	1,736
Total liabilities and capitalization	6,663	5,846

Eliminations

CURRENT ASSETS:				
Cash and cash equivalents	0	0	0	0
Receivables-				
Customers	0	0		
Affiliated companies	(608)	(781)		
Other	0	0		
Notes receivable from affiliated companies	(2,182)	(1,187)		
Materials and supplies, at average cost	0	0		
Derivatives	0	0		
Prepayments and other	1	0		
Total current assets	(2,789)	(1,968)		
PROPERTY, PLANT AND EQUIPMENT:				
In service	(385)	(385)		
Less - Accumulated provision for depreciation	(185)	(180)		
Property, plant and equipment in service net of accumulated provision for depreciation	(200)	(205)		
Construction work in progress	0	0		
Total net property, plant and equipment	(200)	(205)		
INVESTMENTS:				
Nuclear plant decommissioning trusts	0	0		
Investment in affiliated companies	(6,555)	(5,700)		
Other	0	0		
Total other property and investments	(6,555)	(5,700)		
DEFERRED CHARGES AND OTHER ASSETS:				
Accumulated deferred income tax benefits	(270)	(317)		
Customer intangibles	0	0		
Goodwill	0	0		
Property taxes	0	0		
Unamortized sale and leaseback costs	111	75		
Derivatives	0	0		
Other	(111)	(62)		
Total deferred charges and other assets	(270)	(304)		
Total assets	(9,814)	(8,177)		
CURRENT LIABILITIES:				
Currently payable long-term debt	(21)	(20)		
Accounts payable-				
Affiliated companies	(605)	(780)		
Other	0	0		
Accrued Taxes	(4)	(9)		
Derivatives	0	0		
Other	16	42		
Total current liabilities	(2,797)	(1,953)		
CAPITALIZATION:				
Total equity	(6,537)	(5,684)		

Long-term debt and other long-term obligations	(1,218)	(1,230)		
Total capitalization	(7,755)	(6,914)		
NONCURRENT LIABILITIES:				
Deferred gain on sale and leaseback transaction	900	925		
Accumulated deferred income taxes	(162)	(236)		
Asset retirement obligations	0	0		
Retirement benefits	0	0		
Lease market valuation liability	0	0		
Other	0	1		
Total noncurrent liabilities	738	690		
Total liabilities and capitalization	(9,814)	(8,177)		
FES				
CURRENT ASSETS:				
Cash and cash equivalents	3	7	6	9
Receivables-				
Customers	485	424		
Affiliated companies	402	600		
Other	103	61		
Notes receivable from affiliated companies	438	383		
Materials and supplies, at average cost	533	492		
Derivatives	209	219		
Prepayments and other	137	38		
Total current assets	2,310	2,224		
PROPERTY, PLANT AND EQUIPMENT:				
In service	11,638	10,983		
Less - Accumulated provision for depreciation	4,312	4,110		
Property, plant and equipment in service net of accumulated provision for depreciation	7,326	6,873		
Construction work in progress	1,055	1,014		
Total net property, plant and equipment	8,381	7,887		
INVESTMENTS:				
Nuclear plant decommissioning trusts	1,286	1,223		
Investment in affiliated companies	0	0		
Other	16	7		
Total other property and investments	1,302	1,230		
DEFERRED CHARGES AND OTHER ASSETS:				
Accumulated deferred income tax benefits	0	0		
Customer intangibles	114	123		
Goodwill	24	24		
Property taxes	43	43		
Unamortized sale and leaseback costs	111	80		
Derivatives	78	79		
Other	181	129		
Total deferred charges and other assets	551	478		

Total assets	12,544	11,819
CURRENT LIABILITIES:		
Currently payable long-term debt	1,074	905
Accounts payable-		
Affiliated companies	787	436
Other	174	220
Accrued Taxes	83	227
Derivatives	153	189
Other	244	261
Total current liabilities	2,515	2,238
CAPITALIZATION:		
Total equity	3,802	3,577
Long-term debt and other long-term obligations	3,085	2,799
Total capitalization	6,887	6,376
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	900	925
Accumulated deferred income taxes	501	286
Asset retirement obligations	950	904
Retirement benefits	183	356
Lease market valuation liability	87	171
Other	521	563
Total noncurrent liabilities	3,142	3,205
Total liabilities and capitalization	12,544	11,819
Affiliates | FES Corp		
Short-term borrowings-		
Affiliated companies	2,048	1,065
Affiliates | FGCO		
Short-term borrowings-		
Affiliated companies	135	89
Affiliates | Nuclear Generation Corp		
Short-term borrowings-		
Affiliated companies	0	32
Affiliates | Eliminations		
Short-term borrowings-		
Affiliated companies	(2,183)	(1,186)
Affiliates | FES		
Short-term borrowings-		
Affiliated companies	$ 0	$ 0

Consolidated Statements of Cash Flows (Unaudited) (FirstEnergy Corp.) (USD $) In Millions, unless otherwise specified	9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 919	$ 770
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	859	809
Amortization of regulatory assets, net	198	344
Nuclear fuel and lease amortization	163	152
Deferred purchased power and other costs	(214)	(222)
Deferred income taxes and investment tax credits, net	712	696
Deferred rents and lease market valuation liability	(62)	(17)
Accrued compensation and retirement benefits	(168)	(25)
Commodity derivative transactions, net	(80)	(22)
Pension trust contribution	(600)	(375)
Asset impairments	10	59
Cash collateral, net	(3)	(66)
Decrease (increase) in operating assets-		
Receivables	(41)	139
Materials and supplies	(63)	62
Prepayments and other current assets	(151)	(1)
Increase (decrease) in operating liabilities-		
Accounts payable	(250)	(154)
Accrued taxes	(50)	20
Accrued interest	50	67
Other	47	(7)
Net cash provided from operating activities	1,276	2,229
New financing-		
Long-term debt	660	603
Short-term borrowings, net	1,604	0
Redemptions and Repayments-		
Long-term debt	(870)	(1,581)
Short-term borrowings, net	0	(700)
Common stock dividend payments	(690)	(651)
Other	(42)	(73)
Net cash provided from (used for) financing activities	662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,686)	(1,464)
Nuclear fuel	(207)	(65)
Proceeds from asset sales	17	519
Sales of investment securities held in trusts	2,133	3,678
Purchases of investment securities held in trusts	(2,188)	(3,801)

Cash investments	100	51
Cash received in Allegheny merger	0	590
Cost of removal	(119)	(57)
Other	(40)	(6)
Net cash used for investing activities	(1,990)	(555)
Net change in cash and cash equivalents	(52)	(728)
Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	150	291
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction: merger with Allegheny, common stock issued	$ 0	$ 4,354

Consolidated Statements of Income (Unaudited) (FirstEnergy Corp.) (Parenthetical) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Income Statement [Abstract]				
Excise tax collections included in Revenue	$ 123	$ 137	$ 351	$ 371

Consolidated Balance Sheets (Unaudited) (Jersey Central Power & Light Company) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Receivables-		
Customers, net of allowance for uncollectible accounts	$ 1,604	$ 1,525
Other	227	269
Prepaid taxes	227	191
Other	190	122
Total current assets	3,709	3,355
UTILITY PLANT:		
In service	41,756	40,122
Less - Accumulated provision for depreciation	12,434	11,839
Property, plant and equipment in service net of accumulated provision for depreciation	29,322	28,283
Construction work in progress	2,119	2,054
Total net property, plant and equipment	31,441	30,337
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	2,203	2,112
Other	1,038	1,008
Total other property and investments	3,451	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,444	6,441
Regulatory assets	2,113	2,030
Other	1,580	1,641
Total deferred charges and other assets	10,137	10,112
Total assets	48,738	47,326
CURRENT LIABILITIES:		
Currently payable long-term debt	1,473	1,621
Accounts payable-		
Accrued compensation and benefits	313	384
Other	942	900
Total current liabilities	5,920	4,855
Common stockholders' equity-		
Common stock	42	42
Other paid-in capital	9,758	9,765
Accumulated other comprehensive income	367	426
Retained earnings (Accumulated deficit)	3,266	3,047
Total common stockholders' equity	13,433	13,280
Long-term debt and other long-term obligations	15,627	15,716
Total capitalization	29,076	29,015
NONCURRENT LIABILITIES:		

Accumulated deferred income taxes	6,543	5,670
Retirement benefits	2,271	2,823
Asset retirement obligations	1,574	1,497
Other	1,904	2,072
Total noncurrent liabilities	13,742	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	48,738	47,326
JCP&L		
Receivables-		
Customers, net of allowance for uncollectible accounts	250	235
Affiliated companies	40	0
Other	18	17
Prepaid taxes	71	33
Other	43	19
Total current assets	422	304
UTILITY PLANT:		
In service	5,124	4,872
Less - Accumulated provision for depreciation	1,797	1,743
Property, plant and equipment in service net of accumulated provision for depreciation	3,327	3,129
Construction work in progress	114	227
Total net property, plant and equipment	3,441	3,356
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	229	219
Nuclear plant decommissioning trusts	199	193
Other	2	2
Total other property and investments	430	414
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	526	408
Other	29	32
Total deferred charges and other assets	2,366	2,251
Total assets	6,659	6,325
CURRENT LIABILITIES:		
Currently payable long-term debt	35	34
Accounts payable-		
Affiliated companies	1	19
Other	95	101
Accrued compensation and benefits	35	41
Customer deposits	24	24
Accrued interest	30	18
Other	29	36
Total current liabilities	599	532
Common stockholders' equity-		

Common stock	136	136
Other paid-in capital	2,011	2,011
Accumulated other comprehensive income	32	39
Retained earnings (Accumulated deficit)	173	121
Total common stockholders' equity	2,352	2,307
Long-term debt and other long-term obligations	1,711	1,736
Total capitalization	4,063	4,043
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	1,023	859
Power purchase contract liability	267	147
Nuclear fuel disposal costs	197	197
Retirement benefits	163	170
Asset retirement obligations	121	115
Other	226	262
Total noncurrent liabilities	1,997	1,750
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	6,659	6,325

Affiliates | JCP&L

Short-term borrowings-		
Affiliated companies	$ 350	$ 259

Document and Entity Information	9 Months Ended Sep. 30, 2012	Nov. 07, 2012
Entity Information [Line Items]		
Entity Registrant Name	FirstEnergy Solutions Corp.	
Entity Central Index Key	0001407703	
Document Type	10-Q	
Document Period End Date	Sep. 30, 2012	
Amendment Flag	false	
Document Fiscal Year Focus	2012	
Document Fiscal Period Focus	Q3	
Current Fiscal Year End Date	--12-31	
Entity Well Known Seasoned Issuer	Yes	
Entity Voluntary Filers	No	
Entity Current Reporting Status	Yes	
Entity Filer Category	Non-accelerated Filer	
Entity Common Stock Shares Outstanding		7
OE		
Entity Information [Line Items]		
Entity Registrant Name	OHIO EDISON CO	
Entity Central Index Key	0000073960	
Document Type	10-Q	
Document Period End Date	Sep. 30, 2012	
Amendment Flag	false	
Document Fiscal Year Focus	2012	
Document Fiscal Period Focus	Q3	
Current Fiscal Year End Date	--12-31	
Entity Well Known Seasoned Issuer	Yes	
Entity Voluntary Filers	No	
Entity Current Reporting Status	Yes	
Entity Filer Category	Non-accelerated Filer	
Entity Common Stock Shares Outstanding		60
JCP&L		
Entity Information [Line Items]		
Entity Registrant Name	JERSEY CENTRAL POWER & LIGHT CO	
Entity Central Index Key	0000053456	
Document Type	10-Q	
Document Period End Date	Sep. 30, 2012	
Amendment Flag	false	
Document Fiscal Year Focus	2012	
Document Fiscal Period Focus	Q3	
Current Fiscal Year End Date	--12-31	
Entity Well Known Seasoned Issuer	Yes	
Entity Voluntary Filers	No	

Entity Current Reporting Status	Yes	
Entity Filer Category	Non-accelerated Filer	
Entity Common Stock Shares Outstanding		13,628,447

Consolidated Balance Sheets (Unaudited) (Jersey Central Power & Light Company) (Parenthetical) (USD $) In Millions, except Share data, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Common stockholders' equity-		
Common stock, par value (in dollars per share)	$ 0.1	$ 0.1
Common stock, shares authorized	490,000,000	490,000,000
Common stock, shares outstanding	418,216,437	418,216,437
Customer [Member]		
Receivables-		
Allowance for uncollectible accounts	$ 43	$ 37
JCP&L		
Common stockholders' equity-		
Common stock, par value (in dollars per share)	$ 10	$ 10
Common stock, shares authorized	16,000,000	16,000,000
Common stock, shares outstanding	13,628,447	13,628,447
JCP&L | Customer [Member]		
Receivables-		
Allowance for uncollectible accounts	$ 4	$ 3

Consolidated Statements of Comprehensive Income (Unaudited) (FirstEnergy Corp.) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Statement of Income and Comprehensive Income [Abstract]				
NET INCOME	$ 425	$ 530	$ 919	$ 770
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(47)	(48)	(148)	(44)
Amortized gain (loss) on derivative hedges	0	2	1	13
Change in unrealized gain on available-for-sale securities	1	(26)	13	(7)
Other comprehensive income (loss)	(46)	(72)	(134)	(38)
Income taxes (benefits) on other comprehensive income (loss)	(24)	(26)	(75)	(12)
Other comprehensive income (loss), net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
Comprehensive income (loss) attributable to noncontrolling interest	0	(2)	1	(17)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 403	$ 486	$ 859	$ 761

Consolidated Statements of Income and Comprehensive Income (Unaudited) (Ohio Edison Company) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
REVENUES:				
Excise and gross receipts tax collections	$ 123	$ 137	$ 351	$ 371
Total revenues	2,624	3,041	7,414	7,966
OPERATING EXPENSES:				
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
Amortization of regulatory assets, net	61	122	198	344
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME (LOSS)	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Investment income	39	48	63	100
Interest expense	(230)	(267)	(750)	(763)
Capitalized interest	18	17	54	55
Total other income (expense)	(173)	(202)	(633)	(608)
INCOME BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES (BENEFITS)	309	325	658	550
NET INCOME	425	530	919	770
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	425	530	919	770
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(47)	(48)	(148)	(44)
Change in unrealized gain on available-for-sale securities	1	(26)	13	(7)
Other comprehensive income (loss)	(46)	(72)	(134)	(38)
Income taxes (benefits) on other comprehensive income (loss)	(24)	(26)	(75)	(12)
Other comprehensive income (loss), net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
OE				
REVENUES:				
Electric sales	426	441	1,149	1,165
Excise and gross receipts tax collections	28	29	79	82
Total revenues	454	470	1,228	1,247
OPERATING EXPENSES:				
Other operating expenses	124	114	364	316
Provision for depreciation	26	23	75	69
Amortization of regulatory assets, net	42	46	57	49

General taxes	52	51	148	146
Total operating expenses	361	371	987	1,003
OPERATING INCOME (LOSS)	93	99	241	244
OTHER INCOME (EXPENSE):				
Investment income	8	11	17	20
Interest expense	(23)	(22)	(68)	(66)
Capitalized interest	0	0	2	1
Total other income (expense)	(15)	(11)	(49)	(45)
INCOME BEFORE INCOME TAXES	78	88	192	199
INCOME TAXES (BENEFITS)	34	34	76	72
NET INCOME	44	54	116	127
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	44	54	116	127
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(7)	(6)	(24)	(21)
Change in unrealized gain on available-for-sale securities	0	(3)	0	(1)
Other comprehensive income (loss)	(7)	(9)	(24)	(22)
Income taxes (benefits) on other comprehensive income (loss)	(4)	(4)	(13)	(11)
Other comprehensive income (loss), net of tax	(3)	(5)	(11)	(11)
COMPREHENSIVE INCOME	41	49	105	116
OE | Affiliates				
OPERATING EXPENSES:				
Purchased power	38	57	128	220
OE | Non-Affiliates				
OPERATING EXPENSES:				
Purchased power	$ 79	$ 80	$ 215	$ 203

Consolidated Statements of Cash Flows (Unaudited) (FirstEnergy Solutions Corp.) (USD $) In Millions, unless otherwise specified	9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 919	$ 770
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	859	809
Nuclear fuel and lease amortization	163	152
Deferred rents and lease market valuation liability	(62)	(17)
Deferred income taxes and investment tax credits, net	712	696
Asset impairments	10	59
Accrued compensation and retirement benefits	(168)	(25)
Pension trust contribution	(600)	(375)
Commodity derivative transactions, net	(80)	(22)
Cash collateral, net	(3)	(66)
Decrease (increase) in operating assets-		
Receivables	(41)	139
Materials and supplies	(63)	62
Prepayments and other current assets	(151)	(1)
Increase (decrease) in operating liabilities-		
Accounts payable	(250)	(154)
Accrued taxes	(50)	20
Other	47	(7)
Net cash provided from operating activities	1,276	2,229
New financing-		
Long-term debt	660	603
Short-term borrowings, net	1,604	0
Redemptions and Repayments-		
Long-term debt	(870)	(1,581)
Short-term borrowings, net	0	(700)
Other	(42)	(73)
Net cash provided from (used for) financing activities	662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,686)	(1,464)
Nuclear fuel	(207)	(65)
Proceeds from asset sales	17	519
Sales of investment securities held in trusts	2,133	3,678
Purchases of investment securities held in trusts	(2,188)	(3,801)
Other	(40)	(6)
Net cash used for investing activities	(1,990)	(555)
Net change in cash and cash equivalents	(52)	(728)

Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	150	291
FES		
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	222	194
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	203	207
Nuclear fuel and lease amortization	159	151
Deferred rents and lease market valuation liability	(144)	(37)
Deferred income taxes and investment tax credits, net	123	246
Asset impairments	8	40
Accrued compensation and retirement benefits	11	(31)
Pension trust contribution	(209)	0
Commodity derivative transactions, net	(67)	(54)
Cash collateral, net	(4)	(81)
Decrease (increase) in operating assets-		
Receivables	95	(34)
Materials and supplies	(40)	72
Prepayments and other current assets	5	8
Increase (decrease) in operating liabilities-		
Accounts payable	292	(113)
Accrued taxes	(144)	24
Other	(9)	(55)
Net cash provided from operating activities	501	537
New financing-		
Long-term debt	560	247
Short-term borrowings, net	3	0
Redemptions and Repayments-		
Long-term debt	(246)	(791)
Short-term borrowings, net	0	(12)
Other	(9)	(10)
Net cash provided from (used for) financing activities	308	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(535)	(408)
Nuclear fuel	(207)	(65)
Proceeds from asset sales	17	519
Sales of investment securities held in trusts	1,167	1,613
Purchases of investment securities held in trusts	(1,194)	(1,654)
Loans to affiliated companies, net	(55)	57
Other	(6)	(36)
Net cash used for investing activities	(813)	26
Net change in cash and cash equivalents	(4)	(3)
Cash and cash equivalents at beginning of period	7	9
Cash and cash equivalents at end of period	$ 3	$ 6

Pensions and Other Postemployment Benefits	9 Months Ended Sep. 30, 2012
Compensation and Retirement Disclosure [Abstract]	
PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS	

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 pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the nine months ended September 30, 2012, FirstEnergy made a voluntary $600 million contribution to its qualified pension plan. No additional contributions are expected to be made in 2012.

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)	Pensions		OPEB	
For the Three Months Ended September 30,	2012	2011	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)
Net periodic costs (credits)	$ 19	$ 19	$ (45)	$ (46)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	2012	2011	2012	2011
	(In millions)			
Service cost	$ 120	$ 97	$ 9	$ 9
Interest cost	291	276	36	35
Expected return on plan assets	(363)	(332)	(27)	(30)
Amortization of prior service cost	9	12	(153)	(150)
Other adjustments (settlements, curtailments, etc)	—	7	—	—
Net periodic costs (credits)	$ 57	$ 60	$ (135)	$ (136)

Pension and OPEB obligations are allocated to the FE subsidiaries that employ 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) For the Three Months Ended September 30,	Pensions		OPEB	
	2012	2011	2012	2011
	(In millions)			
FirstEnergy	$ 14	$ 14	$ (30)	$ (31)
FES	12	7	(8)	(8)
OE	(1)	(2)	(5)	(5)
JCP&L	(2)	(3)	(3)	(2)

Net Periodic Benefit Costs (Credits) For the Nine Months Ended September 30,	Pensions		OPEB	
	2012	2011	2012	2011
	(In millions)			
FirstEnergy	$ 41	$ 48	$ (92)	$ (97)
FES	33	21	(24)	(24)
OE	(3)	(6)	(16)	(16)
JCP&L	(5)	(8)	(7)	(7)

Consolidated Statements of Cash Flows (Unaudited) (Jersey Central Power & Light Company) (USD $) In Millions, unless otherwise specified	9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 919	$ 770
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	859	809
Amortization of regulatory assets, net	198	344
Deferred purchased power and other costs	(214)	(222)
Deferred income taxes and investment tax credits, net	712	696
Accrued compensation and retirement benefits	(168)	(25)
Pension trust contribution	(600)	(375)
Decrease (increase) in operating assets-		
Receivables	(41)	139
Increase (decrease) in operating liabilities-		
Accounts payable	(250)	(154)
Accrued taxes	(50)	20
Accrued interest	50	67
Other	47	(7)
Net cash provided from operating activities	1,276	2,229
New financing-		
Short-term borrowings, net	1,604	0
Redemptions and Repayments-		
Long-term debt	(870)	(1,581)
Common stock dividend payments	(690)	(651)
Other	(42)	(73)
Net cash provided from (used for) financing activities	662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,686)	(1,464)
Sales of investment securities held in trusts	2,133	3,678
Purchases of investment securities held in trusts	(2,188)	(3,801)
Other	(40)	(6)
Net cash used for investing activities	(1,990)	(555)
Net change in cash and cash equivalents	(52)	(728)
Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	150	291
JCP&L		
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	142	153
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	95	87

Amortization of regulatory assets, net	30	118
Deferred purchased power and other costs	(95)	(84)
Deferred income taxes and investment tax credits, net	156	83
Accrued compensation and retirement benefits	(31)	(12)
Pension trust contribution	0	(105)
Decrease (increase) in operating assets-		
Receivables	(57)	85
Prepaid taxes	(38)	(59)
Increase (decrease) in operating liabilities-		
Accounts payable	(24)	(60)
Accrued taxes	(6)	(1)
Accrued interest	12	12
Other	24	10
Net cash provided from operating activities	208	227
New financing-		
Short-term borrowings, net	91	312
Redemptions and Repayments-		
Long-term debt	(24)	(23)
Common stock dividend payments	(90)	(500)
Other	0	(2)
Net cash provided from (used for) financing activities	(23)	(213)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(157)	(160)
Loans to affiliated companies, net	0	177
Sales of investment securities held in trusts	376	610
Purchases of investment securities held in trusts	(387)	(624)
Other	(17)	(17)
Net cash used for investing activities	(185)	(14)
Net change in cash and cash equivalents	0	0
Cash and cash equivalents at beginning of period	0	0
Cash and cash equivalents at end of period	$ 0	$ 0

Consolidated Statements of Cash Flows (Unaudited) (Ohio Edison Company) (USD $) In Millions, unless otherwise specified	9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 919	$ 770
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	859	809
Amortization of regulatory assets, net	198	344
Deferred income taxes and investment tax credits, net	712	696
Accrued compensation and retirement benefits	(168)	(25)
Pension trust contribution	(600)	(375)
Decrease (increase) in operating assets-		
Receivables	(41)	139
Prepayments and other current assets	(151)	(1)
Increase (decrease) in operating liabilities-		
Accounts payable	(250)	(154)
Accrued taxes	(50)	20
Accrued interest	50	67
Other	47	(7)
Net cash provided from operating activities	1,276	2,229
Redemptions and Repayments-		
Long-term debt	(870)	(1,581)
Short-term borrowings, net	0	(700)
Common stock dividend payments	(690)	(651)
Other	(42)	(73)
Net cash provided from (used for) financing activities	662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,686)	(1,464)
Sales of investment securities held in trusts	2,133	3,678
Purchases of investment securities held in trusts	(2,188)	(3,801)
Cash investments	100	51
Other	(40)	(6)
Net cash used for investing activities	(1,990)	(555)
Net change in cash and cash equivalents	(52)	(728)
Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	150	291
OE		
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	116	127
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	75	69

Amortization of regulatory assets, net	57	49
Amortization of lease costs	28	28
Deferred income taxes and investment tax credits, net	41	72
Accrued compensation and retirement benefits	(35)	(25)
Pension trust contribution	0	(27)
Decrease (increase) in operating assets-		
Receivables	42	50
Prepayments and other current assets	8	(30)
Increase (decrease) in operating liabilities-		
Accounts payable	(43)	(23)
Accrued taxes	7	0
Other	7	(6)
Net cash provided from operating activities	303	284
Redemptions and Repayments-		
Long-term debt	(1)	(1)
Short-term borrowings, net	0	(142)
Common stock dividend payments	(50)	(268)
Other	(1)	(2)
Net cash provided from (used for) financing activities	(52)	(413)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(147)	(123)
Sales of investment securities held in trusts	57	154
Purchases of investment securities held in trusts	(63)	(161)
Loans to affiliated companies, net	(77)	(163)
Cash investments	13	12
Other	(10)	(10)
Net cash used for investing activities	(227)	(291)
Net change in cash and cash equivalents	24	(420)
Cash and cash equivalents at beginning of period	26	420
Cash and cash equivalents at end of period	$ 50	$ 0

Derivative Instruments (Details 2) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Designated as Hedging Instrument [Member]				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Gain (Loss) Recognized in AOCI (Effective Portion)	$ (2)	$ 0	$ (6)	$ 5
Designated as Hedging Instrument [Member] | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				16
Designated as Hedging Instrument [Member] | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				(12)
Designated as Hedging Instrument [Member] | Power Contracts				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Gain (Loss) Recognized in AOCI (Effective Portion)	(2)	0	(6)	4
Designated as Hedging Instrument [Member] | Power Contracts | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				16
Designated as Hedging Instrument [Member] | Power Contracts | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				(12)
Designated as Hedging Instrument [Member] | FTRs				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Gain (Loss) Recognized in AOCI (Effective Portion)	0	0	0	0
Designated as Hedging Instrument [Member] | FTRs | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				

Hedging Relationship; Effective Gain (Loss) Reclassified to:				0
Designated as Hedging Instrument [Member] | FTRs | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				0
Designated as Hedging Instrument [Member] | Interest rate swaps				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Gain (Loss) Recognized in AOCI (Effective Portion)	0	0	0	1
Designated as Hedging Instrument [Member] | Interest rate swaps | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				0
Designated as Hedging Instrument [Member] | Interest rate swaps | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				0
Designated as Hedging Instrument [Member] | Other				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Gain (Loss) Recognized in AOCI (Effective Portion)	0	0	0	0
Designated as Hedging Instrument [Member] | Other | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				0
Designated as Hedging Instrument [Member] | Other | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Hedging Relationship; Effective Gain (Loss) Reclassified to:				0
Not Designated as Hedging Instrument [Member] | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		27		88
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	(27)	(5)	(248)	(41)
Not Designated as Hedging Instrument [Member] | Revenue				

Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		3		(1)
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	52	(20)	278	(35)
Not Designated as Hedging Instrument [Member] | Other Operating Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	2	(19)	84	(61)
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	(10)	(22)	(51)	(77)
Not Designated as Hedging Instrument [Member] | Fuel Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	3		2	
Not Designated as Hedging Instrument [Member] | Interest Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	20			
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	6		6	
Not Designated as Hedging Instrument [Member] | Power Contracts | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		27		88
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	(27)	(5)	(248)	(41)
Not Designated as Hedging Instrument [Member] | Power Contracts | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		3		(1)
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	46	(39)	260	(69)
Not Designated as Hedging Instrument [Member] | Power Contracts | Other Operating Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	7	(11)	69	(65)
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | Power Contracts | Fuel Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				

Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0		0	
Not Designated as Hedging Instrument [Member] | Power Contracts | Interest Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	0			
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0		0	
Not Designated as Hedging Instrument [Member] | FTRs | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		0		0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | FTRs | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		0		0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	6	20	18	36
Not Designated as Hedging Instrument [Member] | FTRs | Other Operating Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	(5)	(9)	12	2
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	(10)	(22)	(51)	(77)
Not Designated as Hedging Instrument [Member] | FTRs | Fuel Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0		0	
Not Designated as Hedging Instrument [Member] | FTRs | Interest Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	0			
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0		0	
Not Designated as Hedging Instrument [Member] | Interest rate swaps | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		0		0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | Interest rate swaps | Revenue				

Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		0		0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	(1)	0	(2)
Not Designated as Hedging Instrument [Member] | Interest rate swaps | Other Operating Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	0	1	0	2
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | Interest rate swaps | Fuel Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0		0	
Not Designated as Hedging Instrument [Member] | Interest rate swaps | Interest Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	20			
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	6		6	
Not Designated as Hedging Instrument [Member] | Other | Purchase Power Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		0		0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | Other | Revenue				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:		0		0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | Other | Other Operating Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	0	0	3	0
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	0	0	0	0
Not Designated as Hedging Instrument [Member] | Other | Fuel Expense				
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships				

Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	3	2
Not Designated as Hedging Instrument [Member] | Other | Interest Expense		
Effect of derivative instruments on the statements of income and comprehensive income for instruments designated in cash flow hedging relationships and not in hedging relationships		
Not in a Hedging Relationship; Unrealized Gain (Loss) Recognized in:	0	
Not in a Hedging Relationship; Realized Gain (Loss) Reclassified to:	$ 0	$ 0

Consolidated Balance Sheets (Unaudited) (Ohio Edison Company) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
CURRENT ASSETS:		
Cash and cash equivalents	$ 150	$ 202
Receivables-		
Customers, net of allowance for uncollectible accounts	1,604	1,525
Other	227	269
Prepayments and other	190	122
Total current assets	3,709	3,355
UTILITY PLANT:		
In service	41,756	40,122
Less - Accumulated provision for depreciation	12,434	11,839
Property, plant and equipment in service net of accumulated provision for depreciation	29,322	28,283
Construction work in progress	2,119	2,054
Total net property, plant and equipment	31,441	30,337
OTHER PROPERTY AND INVESTMENTS:		
Investments in lease obligation bonds	210	402
Nuclear plant decommissioning trusts	2,203	2,112
Other	1,038	1,008
Total other property and investments	3,451	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	2,113	2,030
Other	1,580	1,641
Total deferred charges and other assets	10,137	10,112
Total assets	48,738	47,326
CURRENT LIABILITIES:		
Currently payable long-term debt	1,473	1,621
Accounts payable-		
Accrued taxes	508	558
Other	942	900
Total current liabilities	5,920	4,855
Common stockholders' equity-		
Common stock	42	42
Accumulated other comprehensive income	367	426
Retained earnings (Accumulated deficit)	3,266	3,047
Total common stockholders' equity	13,433	13,280
Noncontrolling interest	16	19
Total equity	13,449	13,299
Long-term debt and other long-term obligations	15,627	15,716
Total capitalization	29,076	29,015

NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,543	5,670
Retirement benefits	2,271	2,823
Asset retirement obligations	1,574	1,497
Other	1,904	2,072
Total noncurrent liabilities	13,742	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	48,738	47,326
OE		
CURRENT ASSETS:		
Cash and cash equivalents	50	26
Receivables-		
Customers, net of allowance for uncollectible accounts	179	163
Affiliated companies	52	86
Other	20	41
Notes receivable from affiliated companies	258	181
Prepayments and other	9	17
Total current assets	568	514
UTILITY PLANT:		
In service	3,490	3,358
Less - Accumulated provision for depreciation	1,308	1,267
Property, plant and equipment in service net of accumulated provision for depreciation	2,182	2,091
Construction work in progress	96	91
Total net property, plant and equipment	2,278	2,182
OTHER PROPERTY AND INVESTMENTS:		
Investments in lease obligation bonds	148	163
Nuclear plant decommissioning trusts	141	137
Other	91	90
Total other property and investments	380	390
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	293	363
Property taxes	81	81
Unamortized sale and leaseback costs	21	25
Other	27	19
Total deferred charges and other assets	422	488
Total assets	3,648	3,574
CURRENT LIABILITIES:		
Currently payable long-term debt	3	2
Accounts payable-		
Affiliated companies	81	119
Other	30	35
Accrued taxes	94	88
Accrued interest	25	25

Other	111	79
Total current liabilities	344	348
Common stockholders' equity-		
Common stock	698	747
Accumulated other comprehensive income	43	54
Retained earnings (Accumulated deficit)	32	(84)
Total common stockholders' equity	773	717
Noncontrolling interest	5	5
Total equity	778	722
Long-term debt and other long-term obligations	1,157	1,155
Total capitalization	1,935	1,877
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	812	787
Retirement benefits	208	213
Asset retirement obligations	75	71
Other	274	278
Total noncurrent liabilities	1,369	1,349
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	$ 3,648	$ 3,574

Consolidated Balance Sheets (Unaudited) (Ohio Edison Company) (Parenthetical) (USD $) In Millions, except Share data, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Common stockholders' equity-		
Common stock, shares authorized	490,000,000	490,000,000
Common stock, shares outstanding	418,216,437	418,216,437
OE		
Common stockholders' equity-		
Common stock, no par value		
Common stock, shares authorized	175,000,000	175,000,000
Common stock, shares outstanding	60	60
Customer [Member]		
Receivables-		
Allowance for uncollectible accounts	43	37
Customer [Member] | OE		
Receivables-		
Allowance for uncollectible accounts	4	4

Consolidated Statements of Income and Comprehensive Income (Unaudited) (Jersey Central Power & Light Company) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
REVENUES:				
Excise and gross receipts tax collections	$ 123	$ 137	$ 351	$ 371
Total revenues	2,624	3,041	7,414	7,966
OPERATING EXPENSES:				
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
Amortization of regulatory assets, net	61	122	198	344
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME (LOSS)	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Interest expense	(230)	(267)	(750)	(763)
Total other income (expense)	(173)	(202)	(633)	(608)
INCOME BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES (BENEFITS)	309	325	658	550
NET INCOME	425	530	919	770
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	425	530	919	770
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(47)	(48)	(148)	(44)
Other comprehensive income (loss)	(46)	(72)	(134)	(38)
Income taxes (benefits) on other comprehensive income (loss)	(24)	(26)	(75)	(12)
Other comprehensive income (loss), net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
JCP&L				
REVENUES:				
Electric sales	625	762	1,579	1,973
Excise and gross receipts tax collections	11	15	29	39
Total revenues	636	777	1,608	2,012
OPERATING EXPENSES:				
Purchased power	331	429	849	1,127
Other operating expenses	84	126	246	279
Provision for depreciation	33	33	95	87
Amortization of regulatory assets, net	2	(4)	30	118
General taxes	17	20	44	53

Total operating expenses	467	604	1,264	1,664
OPERATING INCOME (LOSS)	169	173	344	348
OTHER INCOME (EXPENSE):				
Miscellaneous income	1	4	3	9
Interest expense	(31)	(32)	(92)	(93)
Capitalized interest	0	1	1	2
Total other income (expense)	(30)	(27)	(88)	(82)
INCOME BEFORE INCOME TAXES	139	146	256	266
INCOME TAXES (BENEFITS)	62	61	114	113
NET INCOME	77	85	142	153
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	77	85	142	153
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(6)	(6)	(18)	(17)
Other comprehensive income (loss)	(6)	(6)	(18)	(17)
Income taxes (benefits) on other comprehensive income (loss)	(4)	(2)	(11)	(7)
Other comprehensive income (loss), net of tax	(2)	(4)	(7)	(10)
COMPREHENSIVE INCOME	$ 75	$ 81	$ 135	$ 143

Regulatory Matters (Details) (USD $)	0 Months Ended	9 Months Ended	1 Months Ended	9 Months Ended			9 Months Ended	0 Months Ended	9 Months Ended		0 Months Ended							
	Dec. 09, 2008	Sep. 30, 2012 entities	Apr. 30, 2007 FERC kv	Sep. 30, 2012 FERC class	Jan. 21, 2010 FERC issues	Sep. 30, 2012 FERC PJM	Sep. 30, 2012 FERC PJM FTR Allocation Complaint	Aug. 24, 2012 FERC PATH	Sep. 30, 2012 FERC PATH kv	Sep. 20, 2012 FERC PATH	Aug. 24, 2012 FERC PATH-Allegheny	Aug. 24, 2012 FERC Path-WV	Dec. 28, 2011 FERC PJM Calculation Error	Dec. 28, 2011 FERC PJM Calculation Error FES	Dec. 28, 2011 FERC PJM Calculation Error AE Supply	Sep. 30, 2012 Delivery Year 2011-2012 FERC PJM Calculation Error	Sep. 30, 2012 Delivery Year 2011-2012 FERC PJM Calculation Error FES	Sep. 30, 2012 Delivery Year 2011-2012 FERC PJM Calculation Error AE Supply
Regulatory Matters [Line Items]																		
Regional enforcement entities		8																
Customer power loss period	11 hours																	
Power threshold for cost methodology			500															
Identified issues for written comments					9													
Hybrid methodology, beneficiary pays cost allocation						50.00%												
Hybrid methodology, postage stamp cost allocation						50.00%												
One time payment, ATSI agreed to MISO				1,800,000														
Annual Revenue requirements in Zone				16,000,000														
Number of classes of regulatory proceedings				2														
Losses incurred due to underfunding of contracts													35,000,000	500,000	34,500,000	11,500,000	11,400,000	100,000
Compliance filing period							60 days											
New Voltage transmission facilities across PJM and a zonal transmission rate (In KV)									765									
Cost recovery, PP&E reclassified to Regulatory Assets											62,000,000	59,000,000						
Return on equity for cost recovery								10.90%										
Base return on equity for cost recovery								10.40%										
Return on equity for cost recovery from RTO membership								0.50%										
Remaining Recovery Period of Regulatory Assets								5 years										
Amount of costs sought to be disallowed										$ 6,600,000								

Regulatory Matters (Details) (USD $)	9 Months Ended			1 Months Ended	3 Months Ended	9 Months Ended	12 Months Ended	30 Months Ended	36 Months Ended					9 Months Ended	
	Sep. 30, 2012 MARYLAND	Aug. 31, 2011 MARYLAND	Oct. 06, 2009 MARYLAND	Aug. 31, 2011 OHIO proposals	Oct. 31, 2009 OHIO proposals	Sep. 30, 2012 OHIO plan	Dec. 31, 2009 OHIO	Jun. 30, 2012 OHIO	Dec. 31, 2011 OHIO	Dec. 31, 2010 OHIO	Sep. 30, 2012 OHIO Year 2012 GWh MWh	Sep. 30, 2012 OHIO Year 2013 GWh	Sep. 30, 2012 OHIO Year 2014 GWh	Sep. 30, 2012 OHIO Annually Through 2025 GWh	Sep. 30, 2012 OHIO Annually Through 2018
Proposed electric consumption reduction percentage	10.00%														
Proposed electric demand reduction percentage	15.00%														
Expenditures for cost recovery program		$ 66,000,000	$ 101,000,000												
Recovery period for expenditures for cost recovery program		3 years	6 years												
Maximum penalty assessed, in dollars per day per violation	25,000														
Load cap percentage minimum						80.00%									
Maximum trance award to a single supplier						80.00%									
Generation discount for low income customers						6.00%									
Costs avoided by customers, integration period						5 years									
Costs avoided by customers						360,000,000									
Fund to assist low income customers						12,000,000									
ESP extension term						2 years									
Generation supply auction period, after approval						3 years									
Generation supply auction period, before approval						1 year									
Annual energy savings											1,211	1,726	2,306	2,903	
Increase (decrease) in annual energy savings											416,000				
Utilities required to reduce peak demand							1.00%								
Utilities required to additionally reduce peak demand															0.75%
Period of the portfolio plans filed seeking approval for the program							3 years								
Number of plans						3									
Portfolio plan, estimated cost						250,000,000									
Load served from renewable energy resources								2.00%	1.50%	1.00%					
Request for proposals conducted				2	2										

Regulatory Matters (Details) (USD $)		12 Months Ended						1 Months Ended	9 Months Ended		1 Months Ended		12 Months Ended	1 Months Ended	9 Months Ended	3 Months Ended		9 Months Ended	
	Sep. 30, 2012 PENNSYLVANIA smart_meter	Dec. 31, 2010 PENNSYLVANIA	Sep. 30, 2011 PENNSYLVANIA Party	May 31, 2011 PENNSYLVANIA	Apr. 29, 2011 PENNSYLVANIA questions	Sep. 30, 2012 PENNSYLVANIA Statutory Penalty	Sep. 30, 2012 PENNSYLVANIA Year 2013	Apr. 30, 2010 WEST VIRGINIA	Sep. 30, 2012 WEST VIRGINIA MW	Feb. 28, 2011 WEST VIRGINIA Facilities	Feb. 28, 2011 WEST VIRGINIA City of New Martinsville entities	Feb. 28, 2011 WEST VIRGINIA Morgantown Energy entities	Dec. 31, 2013 WEST VIRGINIA Forecast	Oct. 31, 2006 California Claims Matters FERC Proceedings	Sep. 30, 2012 California Claims Matters FERC	Sep. 30, 2012 Yards Creek Pumped Storage Project FERC MW	Sep. 30, 2012 Yards Creek Pumped Storage Project FERC JCP&L	Sep. 30, 2012 The Seneca Pumped Storage Project FERC MW	Sep. 30, 2012 The Seneca Pumped Storage Project Relicensing
Marginal transmission refund period	29 months																		
Marginal transmission losses		254,000,000																	
Minimum reduction in Utilities reduce energy consumption				1.00%			3.00%												
Minimum reduction in Utilities peak demand							4.50%												
Loss contingency, maximum						20,000,000													
Target installation smart meter	25,000																		
Grace period	30 months																		
Expenditure amortization period	10 years																		
Parties able to challenge recovery amounts			1																
Directed questions for investigation					11														
Annualized base rate increase								40,000,000											
Storm restoration deferral period								5 years											
Additional base rate increase								20,000,000											
Decrease in ENEC rates								20,000,000											
Number of electric generation facilities										3									
Number of electric generation facilities, owned by third party											1	1							
Forecast over energy recovery													66,000,000						
Forecast over energy recovery offset													66,000,000						
Resource plan, proposed transfer									1,653										
Annual load growth rate									1.40%										
Settlement proposal claims															190,000,000				
Court proceedings from filed claims														1					
Hydroelectric project																400		451	
Ownership interest																	50.00%		
Renewal length of operating license																	40 years		
ILP licensure period																	5 years		
Period of cycle																			5 years

	9 Months Ended		21 Months Ended					9 Months Ended	12 Months Ended		9 Months Ended				9 Months Ended			3 Months Ended	9 Months Ended			9 Months Ended			9 Months Ended			9 Months Ended		9 Months Ended	3 Months Ended			3 Months Ended	9 Months Ended			9 Months Ended			16 Months Ended	9 Months Ended							0 Months Ended				
Commitments, Guarantees and Contingencies (Details Textuals) (USD $)	Sep. 30, 2012	Sep. 30, 2011	Dec. 05, 2011 allegation aspect_of_opinion	Dec. 31, 2011	Nov. 07, 2012 Natural Disasters and Other Casualty Events	Oct. 31, 2012 Natural Disasters and Other Casualty Events Customers professional	Nov. 07, 2012 Natural Disasters and Other Casualty Events New Jersey Customers	Sep. 30, 2012 Clean Water Act	Dec. 31, 2010 Clean Water Act mi	Apr. 30, 2009 Clean Water Act aspect_of_opinion	Sep. 30, 2012 Regulation of Waste Disposal options	Sep. 30, 2012 Nuclear Plant Matters canister	Feb. 16, 2012 Nuclear Plant Matters NuclearPowerPlants	Sep. 30, 2012 Caa Compliance ElectricGenerationUnits CoalFiredPlants	Sep. 30, 2012 National Ambient Air Quality Standards T	Sep. 30, 2012 National Ambient Air Quality Standards CAIR phases	Sep. 30, 2012 National Ambient Air Quality Standards CSAPR phases	Sep. 30, 2012 Hazardous Air Pollutant Emissions CoalFiredPlants MW	Sep. 30, 2012 Hazardous Air Pollutant Emissions CoalFiredPlants MW	Sep. 30, 2012 Climate Change celsius	Jan. 02, 2011 Climate Change T	Sep. 30, 2012 Climate Change Year 2020 Increase in funding	Sep. 30, 2012 Senior Secured Term Loan Senior Loans	Sep. 30, 2012 Regulated Distribution	Sep. 30, 2012 FES	Sep. 30, 2011 FES	Dec. 31, 2011 FES	Sep. 30, 2012 FES Hazardous Air Pollutant Emissions	Sep. 30, 2012 AE Supply	Sep. 30, 2012 AE Supply ICG Litigation	Sep. 30, 2012 Global Holding	Sep. 30, 2012 Global Holding Senior Secured Term Loan Senior Loans	Sep. 30, 2012 Global Holding Senior Secured Term Loan Senior Loans Signal Peak, Global Rail and Affiliates	Sep. 30, 2012 Signal Peak and Global Rail	Sep. 30, 2012 Signal Peak and Global Rail Senior Secured Term Loan Senior Loans	Sep. 30, 2012 FEV Senior Secured Term Loan Senior Loans Signal Peak Global Holding	Sep. 30, 2012 WMB Marketing Ventures, LLC Senior Secured Term Loan Senior Loans Signal Peak Global Holding	Sep. 30, 2012 FGCO	Sep. 30, 2011 FGCO	Dec. 31, 2011 FGCO	Feb. 27, 2007 FGCO Clean Water Act spills	Sep. 30, 2012 FGCO Caa Compliance Complaints	Sep. 30, 2012 FGCO Caa Compliance Claim One Complaints IndividualsInAComplaint	Sep. 30, 2012 FGCO Caa Compliance Claim Two plantiffs	Sep. 30, 2012 JCP&L	Sep. 30, 2011 JCP&L	Dec. 31, 2011 JCP&L	Sep. 30, 2012 JCP&L Regulation of Waste Disposal	Aug. 13, 2012 AE Supply and MP ICG Litigation	May 02, 2011 AE Supply and MP ICG Litigation	Sep. 30, 2012 Parental Guarantees	Sep. 30, 2012 Subsidiaries' Guarantees	Sep. 30, 2012 Other Guarantees
Guarantor Obligations [Line Items]																																																					
Outstanding guarantees and other assurances aggregated	$ 4,100,000,000																																																		$ 900,000,000	$ 2,400,000,000	$ 700,000,000
Company posted collateral related to net liability positions																								21,000,000	73,000,000																												
Potential collateral posted related to net liability positions																									40,000,000				11,000,000																								
Senior secured term loan facility, term																															3 years			2 years																			
New syndicated senior secured term loan facility																																350,000,000																					
Repayments of senior secured term loan facility	870,000,000	1,581,000,000																							246,000,000	791,000,000									350,000,000			169,000,000	351,000,000						24,000,000	23,000,000							
Investment ownership percentage																																	69.99%			33.33%	33.33%																
Guarantor obligations, guarantee fee receivable, percentage, remainder of fiscal year																							4.00%																														
Guarantor obligations, guarantee fee receivable, percentage, next twelve months																							5.00%																														
Number of complaints filed against FGCO																																										3											
Number of complaints seek enjoin plant																																										2	1										
Number of individuals behalf of which complaint filed																																											21										
Number of named plaintiffs as class representatives																																												8									
Reduction in air emissions and compliance														81.00%																																							
Number of electric generation facilities														10																																							
Number of generation units														22																																							
Number of phases under the EPA's CAIR for reductions of Sulfur Dioxide and Mono-Nitrogen Oxides																2	2																																				
Capping of SO2 emissions (In Tons)															2,500,000																																						
Capping of NOx emissions (In Tons)															1,300,000																																						
Capping of SO2 Emissions Under CSAPR															2,400,000																																						
Capping of NOx emissions under CSAPR															1,200,000																																						
Potential cost of compliance, MATS																		975,000,000	975,000,000																																		
Number of retired coal-fired plants being retired																		9	9																																		
Megawatt capacity of plants expected to be closed																		3,349	3,349																																		
Pre-tax severance expense related to closures																			14,000,000									10,000,000																									
Upper threshold limit for carbon dioxide emission (Tons per Year)																					75,000																																
Increase (decrease) in global temperature																				2																																	
Funds provided for Copenhagen Green Climate Fund																				30,000,000,000		100,000,000,000																															
Commitment Period by Developed Countries to Provide Funds, Years																				3 years																																	
Aspects of opinion reversed										1																																											
Annual percentage that fish impingement should be reduced to, per CWA								12.00%																																													
Petroleum spills																																									3												
Maximum capital investment required to install technology to meet TDS and Sulfate limits								150,000,000																																													
Portion of Monongahela River subject to CWA 303(d)									68																																												
TMDL Limit Development Period								5 years																																													
Number of days required prior to the filing of a citizen suit under notice								60 days																																													
Claims resolution, civil penalties											800,000																																										
Options proposed by EPA for additional regulation of coal combustion residuals											2																																										
Total environmental liabilities											123,000,000																																				86,000,000					
Environmental Liabilities Former Gas Facilities											79,000,000																																										
Decommissioning Fund Investments	2,203,000,000			2,112,000,000								2,000,000,000													1,286,000,000		1,223,000,000											0		0					199,000,000		193,000,000						
Parental guarantee associated with the funding of decommissioning costs												95,000,000																																									
Request For Information from Number of Nuclear Power Plants, Total													11																																								
Renewal length of operating license for Davis-Besse Nuclear Power Station												20 years																																									
Final rule, determination period												24 months																																									
Number of cooling canisters to be installed												6																																									
Number of cooling canisters, additional installation capacity												47																																									
Loss incurred in damages for replacement coal purchased																														80,000,000																							
Additional damages incurred for future shortfalls																														150,000,000																							
Verdict in Favor																																																		104,000,000			
Amount for which verdict entered for future damages																																																		90,000,000			
Amount for replacement coal and interest																																																		14,000,000			
Gain contingency, unrecorded amount																																																	14,000,000				
Potential MATS Extension Period																		1 year																																			
Number of allegations remanded to trial court			1																																																		
Aspects of opinion under appeal			1																																																		
Gain contingency, damages denied																																																	90,000,000				
Gain contingency, appeal period																																																	30 days				
Number of customers impacted by power outage						2,300,000	1,200,000																																														
Number of professionals working to resolve power outage						20,000																																															
Percentage of impacted customers with power restored					95.00%		85.00%																																														
Expected costs due to catastrophic event					$ 500,000,000																																																
Percentage of expected cost expected to be capitalized or deferred					95.00%																																																

Derivative Instruments (Details Textuals) (USD $)	1 Months Ended	3 Months Ended		9 Months Ended					3 Months Ended		9 Months Ended		3 Months Ended		9 Months Ended	
	Aug. 31, 2012	Sep. 30, 2012 agreements	Jun. 30, 2012 counterparty	Sep. 30, 2012 agreements	Sep. 30, 2011	Dec. 31, 2011	Sep. 30, 2012 JCP&L contracts	Sep. 30, 2012 FES	Sep. 30, 2012 Cash Flow Hedges	Sep. 30, 2011 Cash Flow Hedges	Sep. 30, 2012 Cash Flow Hedges	Sep. 30, 2011 Cash Flow Hedges	Sep. 30, 2012 Fair Value Hedging agreements	Sep. 30, 2011 Fair Value Hedging	Sep. 30, 2012 Fair Value Hedging agreements	Sep. 30, 2011 Fair Value Hedging
Derivative [Line Items]																
Unamortized gains or losses associated with designated cash flow hedges		$ 13,000,000		$ 13,000,000		$ 19,000,000										
Reclassifications from AOCL into other operating expense		2,000,000		(6,000,000)	(18,000,000)											
Gain (loss) on cash flow hedge expected to be reclassified to earnings in next twelve months				8,000,000												
Forward starting swap agreements outstanding		0		0												
Unamortized gains or losses associated with prior interest rate hedges		72,000,000		72,000,000												
Losses to be amortized to interest expenses during next twelve months											9,000,000				23,000,000	
Reclassifications from accumulated other comprehensive loss									2,000,000	3,000,000	7,000,000	9,000,000				
Number of Interest Rate Swap Agreements													0		0	
Gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements		85,000,000		85,000,000												
Reclassifications from long-term debt													6,000,000	5,000,000	17,000,000	16,000,000
Net asset position under commodity derivative contracts		83,000,000		83,000,000												
Collateral posted								33,000,000								
Additional collateral related to commodity derivatives								38,000,000								
Expected adverse change in quoted market prices of derivative instruments		10.00%		10.00%												
Decrease net income due to adverse change in commodity prices				18,000,000												
Notional amount of interest rate derivatives executed in period		1,600,000,000														
Number of counterparties to interest rate derivatives executed in period			16													
Proceeds from termination of interest rate derivatives	$ 6,000,000															
Number of LCAPP contracts							2									
Period In Which LSEs May Request Direct Allocation Of FTRs				2 years												

Pensions and Other Postemployment Benefits (Tables)	9 Months Ended
	Sep. 30, 2012
Compensation and Retirement Disclosure [Abstract]	
Components of Net Periodic Benefit Costs	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)	Pensions		OPEB	
For the Three Months Ended September 30,	**2012**	**2011**	**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)
Net periodic costs (credits)	$ 19	$ 19	$ (45)	$ (46)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	**2012**	**2011**	**2012**	**2011**
	(In millions)			
Service cost	$ 120	$ 97	$ 9	$ 9
Interest cost	291	276	36	35
Expected return on plan assets	(363)	(332)	(27)	(30)
Amortization of prior service cost	9	12	(153)	(150)
Other adjustments (settlements, curtailments, etc)	—	7	—	—
Net periodic costs (credits)	$ 57	$ 60	$ (135)	$ (136)

Components of Net Periodic Benefit Costs Allocated to Subsidiaries

Pension and OPEB obligations are allocated to the FE subsidiaries that employ 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 September 30,	**2012**	**2011**	**2012**	**2011**
	(In millions)			
FirstEnergy	$ 14	$ 14	$ (30)	$ (31)
FES	12	7	(8)	(8)
OE	(1)	(2)	(5)	(5)
JCP&L	(2)	(3)	(3)	(2)

Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	**2012**	**2011**	**2012**	**2011**
	(In millions)			

FirstEnergy	$ 41	$ 48	$ (92)	$ (97)
FES	33	21	(24)	(24)
OE	(3)	(6)	(16)	(16)
JCP&L	(5)	(8)	(7)	(7)

Fair Value Measurements (Details 1) (USD $) In Millions, unless otherwise specified	9 Months Ended Sep. 30, 2012		12 Months Ended Dec. 31, 2011	
Non Utility Generation contract				
Reconciliation of changes in the fair value of NUG contracts				
Beginning Balance, Derivative Asset	$ 57	[1]	$ 122	[1]
Beginning Balance, Derivative Liability	(349)	[1]	(466)	[1]
Beginning Balance, Derivative, Total	(292)	[1]	(344)	[1]
Realized gain (loss), Derivative Asset	0	[1]	0	[1]
Realized gain (loss), Derivative Liability	0	[1]	0	[1]
Realized gain (loss), Derivative Total	0	[1]	0	[1]
Unrealized gain (loss), Derivative Asset	(39)	[1]	(58)	[1]
Unrealized gain (loss), Derivative Liability	(144)	[1]	(144)	[1]
Unrealized gain (loss), Derivative total	(183)	[1]	(202)	[1]
Purchases, Derivative Asset	0	[1]	0	[1]
Purchases, Derivative Liability	0	[1]	0	[1]
Purchases, Derivative Asset and Liability, total	0	[1]	0	[1]
Issuances, Derivative Asset	0	[1]	0	[1]
Issuances, Derivative Liability	0	[1]	0	[1]
Issuances, Derivative Asset and Liability, total	0	[1]	0	[1]
Sales, Derivative Asset	0	[1]	0	[1]
Sales, Derivative Liability	0	[1]	0	[1]
Sales, Derivative Asset and Liability, total	0	[1]	0	[1]
Settlements, Derivative Asset	0	[1]	(7)	[1]
Settlements, Derivative Liability	193	[1]	261	[1]
Settlements, Derivative Asset and Liability, total	193	[1]	254	[1]
Transfers into Level 3, Derivative Asset	0	[1]	0	[1]
Transfers into Level 3, Derivative Liability	0	[1]	0	[1]
Transfers into Level 3, Derivative Asset and Liability, total	0	[1]	0	[1]
Ending Balance, Derivative Asset	18	[1]	57	[1]
Ending Balance, Derivative Liability	(300)	[1]	(349)	[1]
Ending Balance, Derivative, Total	(282)	[1]	(292)	[1]
Non Utility Generation contract | JCP&L				
Reconciliation of changes in the fair value of NUG contracts				
Beginning Balance, Derivative Asset	4		6	[1]
Beginning Balance, Derivative Liability	(147)		(233)	[1]

Beginning Balance, Derivative, Total	(143)		(227)	
Realized gain (loss), Derivative Asset	0	[1]	0	[1]
Realized gain (loss), Derivative Liability	0	[1]	0	[1]
Realized gain (loss), Derivative Total	0		0	
Unrealized gain (loss), Derivative Asset	(3)	[1]	(2)	[1]
Unrealized gain (loss), Derivative Liability	(17)	[1]	(11)	[1]
Unrealized gain (loss), Derivative total	(20)		(13)	
Purchases, Derivative Asset	0	[1]	0	[1]
Purchases, Derivative Liability	0	[1]	0	[1]
Purchases, Derivative Asset and Liability, total	0		0	
Issuances, Derivative Asset	0	[1]	0	[1]
Issuances, Derivative Liability	0	[1]	0	[1]
Issuances, Derivative Asset and Liability, total	0		0	
Sales, Derivative Asset	0	[1]	0	[1]
Sales, Derivative Liability	0	[1]	0	[1]
Sales, Derivative Asset and Liability, total	0		0	
Settlements, Derivative Asset	0	[1]	0	[1]
Settlements, Derivative Liability	39	[1]	97	[1]
Settlements, Derivative Asset and Liability, total	39		97	
Transfers into Level 3, Derivative Asset	0	[1]	0	[1]
Transfers into Level 3, Derivative Liability	0	[1]	0	[1]
Transfers into Level 3, Derivative Asset and Liability, total	0		0	
Ending Balance, Derivative Asset	1		4	
Ending Balance, Derivative Liability	(125)		(147)	
Ending Balance, Derivative, Total	(124)	[1]	(143)	
LCAPP Contracts				
Reconciliation of changes in the fair value of NUG contracts				
Beginning Balance, Derivative Asset	0	[1]		
Beginning Balance, Derivative Liability	0	[1]		
Beginning Balance, Derivative, Total	0	[1]	0	[1]
Realized gain (loss), Derivative Total	0	[1]	0	[1]
Unrealized gain (loss), Derivative total	3	[1]	0	[1]
Purchases, Derivative Asset and Liability, total	(145)	[1]	0	[1]
Issuances, Derivative Asset and Liability, total	0	[1]	0	[1]
Sales, Derivative Asset and Liability, total	0	[1]	0	[1]
Settlements, Derivative Asset and Liability, total	0	[1]	0	[1]
Transfers into Level 3, Derivative Asset and Liability, total	0	[1]	0	[1]
Ending Balance, Derivative Asset	0	[1]	0	[1]

Ending Balance, Derivative Liability	(142)	[1]	0	[1]
Ending Balance, Derivative, Total			0	[1]
LCAPP Contracts | JCP&L				
Reconciliation of changes in the fair value of NUG contracts				
Beginning Balance, Derivative Asset	0		0	[1]
Beginning Balance, Derivative Liability	0		0	[1]
Beginning Balance, Derivative, Total	0		0	
Realized gain (loss), Derivative Asset	0	[1]	0	[1]
Realized gain (loss), Derivative Liability	0	[1]	0	[1]
Realized gain (loss), Derivative Total	0		0	
Unrealized gain (loss), Derivative Asset	0	[1]	0	[1]
Unrealized gain (loss), Derivative Liability	3	[1]	0	[1]
Unrealized gain (loss), Derivative total	3		0	
Purchases, Derivative Asset	0	[1]	0	[1]
Purchases, Derivative Liability	(145)	[1]	0	[1]
Purchases, Derivative Asset and Liability, total	(145)		0	
Issuances, Derivative Asset	0	[1]	0	[1]
Issuances, Derivative Liability	0	[1]	0	[1]
Issuances, Derivative Asset and Liability, total	0		0	
Sales, Derivative Asset	0	[1]	0	[1]
Sales, Derivative Liability	0	[1]	0	[1]
Sales, Derivative Asset and Liability, total	0		0	
Settlements, Derivative Asset	0	[1]	0	[1]
Settlements, Derivative Liability	0	[1]	0	[1]
Settlements, Derivative Asset and Liability, total	0		0	
Transfers into Level 3, Derivative Asset	0	[1]	0	[1]
Transfers into Level 3, Derivative Liability	0	[1]	0	[1]
Transfers into Level 3, Derivative Asset and Liability, total	0		0	
Ending Balance, Derivative Asset	0		0	
Ending Balance, Derivative Liability	(142)		0	
Ending Balance, Derivative, Total	(142)		0	
FTRs				
Reconciliation of changes in the fair value of NUG contracts				
Beginning Balance, Derivative Asset	1		0	
Beginning Balance, Derivative Liability	(23)		0	
Beginning Balance, Derivative, Total	(22)		0	
Realized gain (loss), Derivative Asset	0		0	
Realized gain (loss), Derivative Liability	0		0	
Realized gain (loss), Derivative Total	0		0	
Unrealized gain (loss), Derivative Asset	1		2	

Unrealized gain (loss), Derivative Liability	(4)	(27)
Unrealized gain (loss), Derivative total	(3)	(25)
Purchases, Derivative Asset	12	13
Purchases, Derivative Liability	(10)	(4)
Purchases, Derivative Asset and Liability, total	2	9
Issuances, Derivative Asset	0	0
Issuances, Derivative Liability	0	0
Issuances, Derivative Asset and Liability, total	0	0
Sales, Derivative Asset	0	0
Sales, Derivative Liability	0	0
Sales, Derivative Asset and Liability, total	0	0
Settlements, Derivative Asset	(7)	(14)
Settlements, Derivative Liability	26	20
Settlements, Derivative Asset and Liability, total	19	6
Transfers into Level 3, Derivative Asset	0	0
Transfers into Level 3, Derivative Liability	0	(12)
Transfers into Level 3, Derivative Asset and Liability, total	0	(12)
Ending Balance, Derivative Asset	7	1
Ending Balance, Derivative Liability	(11)	(23)
Ending Balance, Derivative, Total	(4)	(22)
FTRs | FES		
Reconciliation of changes in the fair value of NUG contracts		
Beginning Balance, Derivative Asset	1	0
Beginning Balance, Derivative Liability	(7)	0
Beginning Balance, Derivative, Total	(6)	0
Realized gain (loss), Derivative Asset	0	0
Realized gain (loss), Derivative Liability	0	0
Realized gain (loss), Derivative Total	0	0
Unrealized gain (loss), Derivative Asset	1	4
Unrealized gain (loss), Derivative Liability	(2)	(8)
Unrealized gain (loss), Derivative total	(1)	(4)
Purchases, Derivative Asset	8	2
Purchases, Derivative Liability	(7)	(1)
Purchases, Derivative Asset and Liability, total	1	1
Issuances, Derivative Asset	0	0
Issuances, Derivative Liability	0	0
Issuances, Derivative Asset and Liability, total	0	0
Sales, Derivative Asset	0	0
Sales, Derivative Liability	0	0
Sales, Derivative Asset and Liability, total	0	0
Settlements, Derivative Asset	(5)	(5)
Settlements, Derivative Liability	9	2
Settlements, Derivative Asset and Liability, total	4	(3)
Transfers into Level 3, Derivative Asset	0	0

Transfers into Level 3, Derivative Liability	0	0
Transfers into Level 3, Derivative Asset and Liability, total	0	0
Ending Balance, Derivative Asset	5	1
Ending Balance, Derivative Liability	(7)	(7)
Ending Balance, Derivative, Total	$ (2)	$ (6)

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

Goodwill	9 Months Ended Sep. 30, 2012
Goodwill and Intangible Assets Disclosure [Abstract]	
GOODWILL	**GOODWILL** On January 1, 2012, FirstEnergy adopted the amendment to the authoritative accounting guidance regarding the testing for goodwill impairment that provides the option to apply a qualitative assessment to determine whether or not it is necessary to apply the traditional two-step quantitative goodwill impairment test. In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, a likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying amount. If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing of goodwill assigned to its reporting units is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify potential goodwill impairment and measure the amount of goodwill impaired to be recognized, if any. The 2012 annual goodwill impairment test was performed during the third quarter primarily using a qualitative assessment approach. FirstEnergy assessed economic, industry and market considerations in addition to overall financial performance of its reporting units. FirstEnergy's reporting units are consistent with its operating entities, which aggregate to reportable segments and consist of Regulated Distribution, Regulated Transmission and Competitive Energy Services. Goodwill is allocated to these reportable segments based on the original purchase price allocation for acquisitions within the various reporting units. As of September 30, 2012, goodwill balances for the Regulated Distribution, Regulated Transmission and Competitive Energy Services segments were $5,025 million, $526 million and $893 million, respectively. It was determined that the fair values of FirstEnergy's reporting units were, more likely than not, greater than their carrying values. No further goodwill testing was completed and no impairment was recognized.

Fair Value Measurements	9 Months Ended Sep. 30, 2012

Fair Value Disclosures [Abstract]

FAIR VALUE MEASUREMENTS

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, which 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 8, 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 September 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 nine months ended September 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.

FirstEnergy

Recurring Fair Value Measurements	**September 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	$ —	$ 1,012	$ —	1,012	$ —	$ 1,544	$ —	$ 1,544
Derivative assets - commodity contracts	3	257	—	260	—	264	—	264
Derivative assets - FTRs	—	—	7	7	—	—	1	1
Derivative assets - NUG contracts[1]	—	—	18	18	—	—	56	56
Equity securities[2]	367	—	—	367	259	—	—	259
Foreign government debt securities	—	60	—	60	—	3	—	3
U.S. government debt securities	—	184	—	184	—	148	—	148
U.S. state debt securities	—	314	—	314	—	314	—	314
Other[3]	124	562	—	686	49	225	—	274
Total assets	494	2,389	25	2,908	308	2,498	57	2,863
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(247)	—	(247)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(23)	(23)
Derivative liabilities - NUG contracts[1]	—	—	(300)	(300)	—	—	(349)	(349)
Derivative liabilities - LCAPP contracts[1]	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	(177)	(453)	(630)	—	(247)	(372)	(619)
Net assets (liabilities)[4]	$ 494	$ 2,212	$ (428)	$ 2,278	$ 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 $43 million and $(52) million as of September 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 and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 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**
					(in millions)				
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)	(39)	(144)	(183)	—	3	3	1	(4)	(3)
Purchases	—	—	—	—	(145)	(145)	12	(10)	2
Issues	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	—	193	193	—	—	—	(7)	26	19
Transfers in (out) of Level 3	—	—	—	—	—	—	—	—	—
September 30, 2012 Balance	$ 18	$ (300)	$ (282)	$ —	$ (142)	$ (142)	$ 7	$ (11)	$ (4)

(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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (4)	Model	RTO auction clearing prices	($3.80) to $6.40	$ 0.50	Dollars/MWH
NUG Contracts	$ (282)	Model	Generation Electricity regional prices	700 to 6,748,000 $43.40 to $57.30	3,211,000 $51.90	MWH Dollars/MWH
LCAPP Contracts	$ (142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

FES

Recurring Fair Value Measurements	September 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	$ —	$ 437	$ —	$ 437	$ —	$ 1,010	$ —	$ 1,010
Derivative assets - commodity contracts	3	252	—	255	—	248	—	248
Derivative assets - FTRs	—	—	5	5	—	—	1	1
Equity securities(1)	334	—	—	334	124	—	—	124
Foreign government debt securities	—	50	—	50	—	3	—	3
U.S. government debt securities	—	21	—	21	—	7	—	7
U.S. state debt securities	—	—	—	—	—	5	—	5
Other(2)	—	396	—	396	—	132	—	132
Total assets	337	1,156	5	1,498	124	1,405	1	1,530
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(234)	—	(234)
Derivative liabilities - FTRs	—	—	(7)	(7)	—	—	(7)	(7)
Total liabilities	—	(177)	(7)	(184)	—	(234)	(7)	(241)
Net assets (liabilities)(3)	$ 337	$ 979	$ (2)	$ 1,314	$ 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 $47 million and $(58) million as of September 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 September 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	(2)	(1)

Purchases	8	(7)	1
Issues	—	—	—
Sales	—	—	—
Settlements	(5)	9	4
Transfers in (out) of Level 3	—	—	—
September 30, 2012 Balance	$ 5	$ (7)	$ (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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (2)	Model	RTO auction clearing prices	($3.80) to $6.40	$0.30	Dollars/ MWH

OE

Recurring Fair Value Measurements	September 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 and $1 million as of September 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	September 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	$ —	$ 139	$ —	$ 139	$ —	$ 144	$ —	$ 144
Derivative assets - NUG contracts[1]	—	—	1	1	—	—	4	4
Equity securities[2]	—	—	—	—	30	—	—	30
Foreign government debt securities	—	2	—	2	—	—	—	—
U.S. government debt securities	—	8	—	8	—	2	—	2
U.S. state debt securities	—	230	—	230	—	219	—	219
Other[3]	—	48	—	48	—	15	—	15
Total assets	—	427	1	428	30	380	4	414
Liabilities								
Derivative liabilities - NUG contracts[1]	—	—	(125)	(125)	—	—	(147)	(147)
Derivative liabilities - LCAPP contracts[1]	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	—	(267)	(267)	—	—	(147)	(147)
Net assets (liabilities)[4]	$ —	$ 427	$ (266)	$ 161	$ 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 $1 million and $2 million as of September 30, 2012 and December 31, 2011 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 NUG and LCAPP contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2012 and December 31, 2011:

	NUG Contracts[1]	LCAPP Contracts[1]

	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
			(in millions)			
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)	(3)	(17)	(20)	—	3	3
Purchases	—	—	—	—	(145)	(145)
Issues	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	39	39	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
September 30, 2012 Balance	$ 1	$ (125)	$(124)	$ —	$ (142)	$(142)

(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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
NUG Contracts	$ (124)	Model	Generation Electricity regional prices	95,000 to 1,324,000 $45.50 to $59.50	405,000 $54.10	MWH Dollars/MWH
LCAPP Contracts	$ (142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	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 OTTI. 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 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 and NUG trusts as of September 30, 2012 and December 31, 2011:

September 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								
FirstEnergy	$ 1,529	$ 37	$ —	$ 1,566	$ 1,980	$ 25	$ —	$ 2,005
FES	500	8	—	508	1,012	13	—	1,025
OE	137	—	—	137	134	—	—	134
JCP&L	364	13	—	377	356	7	—	363
Equity securities								
FirstEnergy	$ 320	$ 46	$ —	$ 366	$ 222	$ 36	$ —	$ 258
FES	295	38	—	333	104	20	—	124
JCP&L	—	—	—	—	27	3	—	30

(1) Excludes short-term cash investments: FE Consolidated - $596 million; FES - $443 million; OE - $3 million; JCP&L - $51 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 nine months ended September 30, 2012 and 2011 were as follows:

Three Months Ended

September 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,751	$ 81	$ (32)	$ 18
FES	1,059	60	(23)	10
OE	—	—	—	1
JCP&L	211	6	(2)	4

September 30, 2011	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,974	$ 98	$ (38)	$ 20
FES	1,100	52	(19)	9
OE	134	7	(1)	1
JCP&L	234	11	(4)	5

Nine Months Ended

September 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 2,133	$ 118	$ (67)	$ 51
FES	1,167	85	(48)	27
OE	57	—	—	2
JCP&L	376	8	(4)	11

September 30, 2011	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 3,678	$ 220	$ (83)	$ 72
FES	1,613	74	(42)	41
OE	154	7	(1)	3
JCP&L	610	37	(10)	13

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 September 30, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011

	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt Securities						
FirstEnergy	$ 210	$ 58	$ 268	$ 402	$ 50	$ 452
OE	148	33	181	163	21	184

Investments in emission allowances, employee benefit trusts and cost and equity method investments totaling $709 million as of September 30, 2012, and $693 million as of December 31, 2011, are excluded from the amounts reported above.

Notes Receivable

FES has a long-term note receivable of $4 million as of September 30, 2012 that matures in December 2013. Due to the short duration of this note, it is recorded at cost which approximates fair value.

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. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts, as of September 30, 2012 and December 31, 2011:

	September 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
FirstEnergy	$ 16,942	$ 19,677	$ 17,165	$ 19,320
FES	4,133	4,494	3,675	3,931
OE	1,157	1,500	1,157	1,434
JCP&L	1,753	2,092	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 September 30, 2012 and December 31, 2011.

Variable Interest Entities (Details Textuals) (USD $)	3 Months Ended		9 Months Ended					3 Months Ended		9 Months Ended		3 Months Ended		9 Months Ended		1 Months Ended	3 Months Ended		9 Months Ended		3 Months Ended		9 Months Ended				9 Months Ended	0 Months Ended					0 Months Ended	3 Months Ended	1 Months Ended
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012 contracts	Sep. 30, 2012 entities	Sep. 30, 2011	Sep. 30, 2012 Power Purchase Agreements agreements	Aug. 24, 2012 PJM	Sep. 30, 2012 JCP&L	Sep. 30, 2011 JCP&L	Sep. 30, 2012 JCP&L	Sep. 30, 2011 JCP&L contracts	Sep. 30, 2012 JCP&L Power Purchase Agreements	Sep. 30, 2011 JCP&L Power Purchase Agreements	Sep. 30, 2012 JCP&L Power Purchase Agreements	Sep. 30, 2011 JCP&L Power Purchase Agreements	Oct. 31, 2012 JCP&L Power Purchase Agreements Cancellation of Contract [Member] contracts	Sep. 30, 2012 PE Power Purchase Agreements	Sep. 30, 2011 PE Power Purchase Agreements	Sep. 30, 2012 PE Power Purchase Agreements	Sep. 30, 2011 PE Power Purchase Agreements	Sep. 30, 2012 WP Power Purchase Agreements	Sep. 30, 2011 WP Power Purchase Agreements	Sep. 30, 2012 WP Power Purchase Agreements	Sep. 30, 2011 WP Power Purchase Agreements	Oct. 18, 2011 Signal Peak FEV	Sep. 30, 2012 Signal Peak FEV Global Holding	Sep. 30, 2012 Variable Interest Entity, Not Primary Beneficiary	Aug. 24, 2012 PATH	Aug. 24, 2012 PATH-Allegheny	Aug. 24, 2012 Path-WV	Sep. 30, 2012 Path-WV	Sep. 30, 2012 Oyster Creek Nuclear Generating Station	Aug. 24, 2012 Beaver Valley Unit 2 Nuclear Generation Corp	Sep. 30, 2012 Bruce Mansfield Plant FGCO	Nov. 08, 2012 Bruce Mansfield Plant FGCO Acquisition [Member]
Variable Interest Entities (Textuals) [Abstract]																																			
Bondable stranded costs																																$ 253,000,000			
Environmental control bond	493,000,000		493,000,000	493,000,000																															
Income (loss) attributable to noncontrolling interest	0	(2,000,000)		1,000,000	(17,000,000)																						1,000,000								
Distributions to owners																											4,000,000								
Joint venture, ownership percentage by parent																									50.00%										
Ownership interest																										33.33%									
Remaining Recovery Period of Regulatory Assets																												5 years							
Percentage of high-voltage transmission line project owned by subsidiary of AE on the Allegheny Series																															100.00%				
Percentage of high-voltage transmission line project owned by subsidiary of AE on the West Virginia Series																															50.00%				
Regulatory asset expansion, canceled							2,100,000,000																												
Cost recovery, PP&E reclassified to Regulatory Assets																												121,000,000	62,000,000	59,000,000					
Return on equity for cost recovery																												10.90%							
Base return on equity for cost recovery																												10.40%							
Return on equity for cost recovery from RTO membership																												0.50%							
Number of long-term power purchase agreements maintained by FirstEnergy with NUG entities						21																													
Number of Contracts, Ended in Period, Power Purchase Agreement with Non-Utility Generation Entity																1																			
Number of contracts that may contain variable interest			3	3							4																								
Purchased power	1,312,000,000	1,349,000,000		3,815,000,000	3,755,000,000			331,000,000	429,000,000	849,000,000	1,127,000,000	19,000,000	44,000,000	46,000,000	164,000,000		30,000,000	31,000,000	89,000,000	89,000,000	16,000,000	14,000,000	49,000,000	40,000,000											
Reserve for adverse purchase power commitment																					45,000,000		45,000,000												
Current liability included in adverse purchase power commitment																					11,000,000		11,000,000												
Purchase of lessor equity interests in sale and leaseback																																	108,000,000	95,400,000	37,600,000
Early buyout option exercise																																			23,600,000
Net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments	$ 1,400,000,000		$ 1,400,000,000	$ 1,400,000,000																															

Organization and Basis of Presentation (Details) (USD $) In Millions, unless otherwise specified	3 Months Ended
	Dec. 31, 2011
Organization, Consolidation and Presentation of Financial Statements [Abstract]	
Increase in income tax expense resulting from purchase accounting adjustment	$ 20
Decrease in goodwill resulting from purchase accounting adjustment	$ (20)

Consolidated Balance Sheets (Unaudited) (FirstEnergy Corp.) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
CURRENT ASSETS:		
Cash and cash equivalents	$ 150	$ 202
Receivables-		
Customers, net of allowance for uncollectible accounts	1,604	1,525
Other, net of allowance for uncollectible accounts	227	269
Materials and supplies	875	811
Prepaid taxes	227	191
Derivatives	212	235
Accumulated deferred income taxes	224	0
Other	190	122
Total current assets	3,709	3,355
PROPERTY, PLANT AND EQUIPMENT:		
In service	41,756	40,122
Less - Accumulated provision for depreciation	12,434	11,839
Property, plant and equipment in service net of accumulated provision for depreciation	29,322	28,283
Construction work in progress	2,119	2,054
Total net property, plant and equipment	31,441	30,337
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,203	2,112
Investments in lease obligation bonds	210	402
Other	1,038	1,008
Total other property and investments	3,451	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,444	6,441
Regulatory assets	2,113	2,030
Other	1,580	1,641
Total deferred charges and other assets	10,137	10,112
Total assets	48,738	47,326
CURRENT LIABILITIES:		
Currently payable long-term debt	1,473	1,621
Short-term borrowings	1,604	0
Accounts payable	925	1,174
Accrued taxes	508	558
Accrued compensation and benefits	313	384
Derivatives	155	218
Other	942	900
Total current liabilities	5,920	4,855
Common stockholders' equity-		

Common stock	42	42
Other paid-in capital	9,758	9,765
Accumulated other comprehensive income	367	426
Retained earnings (Accumulated deficit)	3,266	3,047
Total common stockholders' equity	13,433	13,280
Noncontrolling interest	16	19
Total equity	13,449	13,299
Long-term debt and other long-term obligations	15,627	15,716
Total capitalization	29,076	29,015
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,543	5,670
Retirement benefits	2,271	2,823
Asset retirement obligations	1,574	1,497
Deferred gain on sale and leaseback transaction	900	925
Adverse power contract liability	550	469
Other	1,904	2,072
Total noncurrent liabilities	13,742	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
Total liabilities and capitalization	$ 48,738	$ 47,326

Consolidated Balance Sheets (Unaudited) (FirstEnergy Solutions Corp.) (Parenthetical) (USD $) In Millions, except Share data, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Common stockholders' equity-		
Common stock, shares authorized	490,000,000	490,000,000
Common stock, shares outstanding	418,216,437	418,216,437
Customer [Member]		
Receivables-		
Allowance for uncollectible accounts	43	37
Other Receivables [Member]		
Receivables-		
Allowance for uncollectible accounts	2	3
FES		
Common stockholders' equity-		
Common stock, no par value		
Common stock, shares authorized	750	750
Common stock, shares outstanding	7	7
FES | Customer [Member]		
Receivables-		
Allowance for uncollectible accounts	16	16
FES | Other Receivables [Member]		
Receivables-		
Allowance for uncollectible accounts	2	3

Derivative Instruments (Details) (USD $) In Millions, unless otherwise specified	Sep. 30, 2012	Dec. 31, 2011
Fair value of commodity derivatives		
Economic Hedges Derivative assets	$ 285	$ 321
Economic Hedges Derivative liabilities	(630)	(619)
Power Contracts | Current Assets		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	178	185
Power Contracts | Current Liabilities		
Fair value of commodity derivatives		
Economic Hedges Derivative liabilities	(146)	(196)
Power Contracts | Noncurrent Assets		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	79	79
Power Contracts | Noncurrent Liabilities		
Fair value of commodity derivatives		
Economic Hedges Derivative liabilities	(31)	(51)
FTRs | Current Assets		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	7	1
FTRs | Current Liabilities		
Fair value of commodity derivatives		
Economic Hedges Derivative liabilities	(9)	(22)
FTRs | Noncurrent Assets		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	0	0
FTRs | Noncurrent Liabilities		
Fair value of commodity derivatives		
Economic Hedges Derivative liabilities	(2)	(1)
NUGs		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	18	56
Economic Hedges Derivative liabilities	(300)	(349)
LCAPP		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	0	0
Economic Hedges Derivative liabilities	(142)	0
Other | Current Assets		
Fair value of commodity derivatives		
Economic Hedges Derivative assets	3	0
Other | Current Liabilities		
Fair value of commodity derivatives		

Economic Hedges Derivative liabilities	$ 0	$ 0

Supplemental Guarantor Information (Details 2) (USD $) In Millions, unless otherwise specified	3 Months Ended		9 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2012	Sep. 30, 2011
Consolidated Statements of Cash Flows [Abstract]				
Net cash provided from operating activities			$ 1,276	$ 2,229
New Financing-				
Long-term debt			660	603
Short-term borrowings, net			1,604	0
Redemptions and Repayments-				
Long-term debt			(870)	(1,581)
Short-term borrowings, net			0	(700)
Other			(42)	(73)
Net cash provided from (used for) financing activities			662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(775)	(500)	(1,686)	(1,464)
Nuclear fuel			(207)	(65)
Proceeds from asset sales			17	519
Sales of investment securities held in trusts			2,133	3,678
Purchases of investment securities held in trusts			(2,188)	(3,801)
Other			(40)	(6)
Net cash used for investing activities			(1,990)	(555)
Net change in cash and cash equivalents			(52)	(728)
Cash and cash equivalents at beginning of period			202	1,019
Cash and cash equivalents at end of period	150	291	150	291
FES Corp				
Consolidated Statements of Cash Flows [Abstract]				
Net cash provided from operating activities			(971)	(367)
New Financing-				
Long-term debt			0	0
Short-term borrowings, net			982	750
Redemptions and Repayments-				
Long-term debt			0	(136)
Short-term borrowings, net			0	0
Other			(1)	(8)
Net cash provided from (used for) financing activities			981	606
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions			(10)	(8)
Nuclear fuel			0	0
Proceeds from asset sales			0	9
Sales of investment securities held in trusts			0	0
Purchases of investment securities held in trusts			0	0
Loans to affiliated companies, net			1	(228)

Other			(1)	(12)
Net cash used for investing activities			(10)	(239)
Net change in cash and cash equivalents			0	0
Cash and cash equivalents at beginning of period			0	0
Cash and cash equivalents at end of period	0	0	0	0
FGCO				
Consolidated Statements of Cash Flows [Abstract]				
Net cash provided from operating activities			683	539
New Financing-				
Long-term debt			317	140
Short-term borrowings, net			49	59
Redemptions and Repayments-				
Long-term debt			(169)	(351)
Short-term borrowings, net			0	0
Other			(6)	(1)
Net cash provided from (used for) financing activities			191	(153)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions			(175)	(143)
Nuclear fuel			0	0
Proceeds from asset sales			17	510
Sales of investment securities held in trusts			0	0
Purchases of investment securities held in trusts			0	0
Loans to affiliated companies, net			(715)	(732)
Other			(5)	(24)
Net cash used for investing activities			(878)	(389)
Net change in cash and cash equivalents			(4)	(3)
Cash and cash equivalents at beginning of period			7	9
Cash and cash equivalents at end of period	3	6	3	6
Nuclear Generation Corp				
Consolidated Statements of Cash Flows [Abstract]				
Net cash provided from operating activities			799	374
New Financing-				
Long-term debt			243	107
Short-term borrowings, net			0	25
Redemptions and Repayments-				
Long-term debt			(87)	(313)
Short-term borrowings, net			(32)	0
Other			(2)	(2)
Net cash provided from (used for) financing activities			122	(183)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions			(350)	(257)
Nuclear fuel			(207)	(65)
Proceeds from asset sales			0	0
Sales of investment securities held in trusts			1,167	1,613

Purchases of investment securities held in trusts			(1,194)	(1,654)
Loans to affiliated companies, net			(337)	172
Other			0	0
Net cash used for investing activities			(921)	(191)
Net change in cash and cash equivalents			0	0
Cash and cash equivalents at beginning of period			0	0
Cash and cash equivalents at end of period	0	0	0	0
Eliminations				
Consolidated Statements of Cash Flows [Abstract]				
Net cash provided from operating activities			(10)	(9)
New Financing-				
Long-term debt			0	0
Short-term borrowings, net			(1,028)	(834)
Redemptions and Repayments-				
Long-term debt			10	9
Short-term borrowings, net			32	(12)
Other				1
Net cash provided from (used for) financing activities			(986)	(836)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions			0	0
Nuclear fuel			0	0
Proceeds from asset sales			0	0
Sales of investment securities held in trusts			0	0
Purchases of investment securities held in trusts			0	0
Loans to affiliated companies, net			996	845
Other			0	0
Net cash used for investing activities			996	845
Net change in cash and cash equivalents			0	0
Cash and cash equivalents at beginning of period			0	0
Cash and cash equivalents at end of period	0	0	0	0
FES				
Consolidated Statements of Cash Flows [Abstract]				
Net cash provided from operating activities			501	537
New Financing-				
Long-term debt			560	247
Short-term borrowings, net			3	0
Redemptions and Repayments-				
Long-term debt			(246)	(791)
Short-term borrowings, net			0	(12)
Other			(9)	(10)
Net cash provided from (used for) financing activities			308	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions			(535)	(408)
Nuclear fuel			(207)	(65)

Proceeds from asset sales			17	519
Sales of investment securities held in trusts			1,167	1,613
Purchases of investment securities held in trusts			(1,194)	(1,654)
Loans to affiliated companies, net			(55)	57
Other			(6)	(36)
Net cash used for investing activities			(813)	26
Net change in cash and cash equivalents			(4)	(3)
Cash and cash equivalents at beginning of period			7	9
Cash and cash equivalents at end of period	$ 3	$ 6	$ 3	$ 6

Derivative Instruments	9 Months Ended Sep. 30, 2012
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
DERIVATIVE INSTRUMENTS	**DERIVATIVE INSTRUMENTS** FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps. FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 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 instruments previously designated to be in a cash flow hedging relationship totaled $13 million and $19 million as of September 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 $2 million and less than $1 million of income during the three months ended September 30, 2012 and 2011, respectively, and $6 million of income and $18 million of loss during the nine months ended September 30, 2012 and 2011, respectively. Approximately $8 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 September 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 $72 million as of September 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 September 30, 2012 and 2011, respectively, and $7 million and $9 million during the nine months ended September 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 September 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 $85 million as of September 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 and $5 million during the three months ended September 30, 2012 and 2011, respectively, and $17 million and $16 million during the nine months ended September 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 September 30, 2012, FirstEnergy's net asset position under commodity derivative contracts was $83 million, which related to FES and AE Supply positions. Under these commodity derivative contracts, FES posted $33 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $38 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 September 30, 2012, an adverse 10% change in commodity prices would decrease net income by approximately $18 million during the next twelve months.

Interest Rate Swaps

FirstEnergy has used 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 were 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. Changes in fair value of the forward starting swap agreements were recorded in net income on a market-to-market basis. 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. In August 2012, FirstEnergy terminated all of the forward starting swap agreements that were executed in the second quarter, resulting in a net gain, recorded as a reduction to interest expense, and cash proceeds of approximately $6 million.

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 with a corresponding regulatory asset. 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			**Derivative Liabilities**		
	Fair Value			**Fair Value**	
	September 30, 2012	**December 31, 2011**		**September 30, 2012**	**December 31, 2011**
	(In millions)			***(In millions)***	
Power Contracts			Power Contracts		
Current Assets	$ 178	$ 185	Current Liabilities	$ (146)	$ (196)

Noncurrent Assets	79	79	Noncurrent Liabilities	(31)	(51)
FTRs			FTRs		
Current Assets	7	1	Current Liabilities	(9)	(22)
Noncurrent Assets	—	—	Noncurrent Liabilities	(2)	(1)
NUGs	18	56	NUGs	(300)	(349)
LCAPP	—	—	LCAPP	(142)	—
Other Current Assets	3	—	Other Current Liabilities	—	—
	$ 285	$ 321		$ (630)	$ (619)

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

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	33	38	(5)	MWH
FTRs	67	—	67	MWH
NUGs	16	—	16	MWH
LCAPP	408	—	408	MW
Natural Gas	16	—	16	BTUs

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

	Three Months Ended September 30				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$ (2)	$ —	$ —	$ —	$ (2)
2011					
Gain (Loss) Recognized in AOCI (Effective Portion)	$ —	$ —	$ —	$ —	$ —
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain (Loss) Recognized in:					
Other Operating Expense	$ 7	$ (5)	$ —	$ —	$ 2
Interest Expense	—	—	20	—	20
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (27)	$ —	$ —	$ —	$ (27)
Revenues	46	6	—	—	52
Other Operating Expense	—	(10)	—	—	(10)
Fuel Expense	—	—	—	3	3
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$ 27	$ —	$ —	$ —	$ 27

	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
Revenues	3	—	—	—	3
Other Operating Expense	(11)	(9)	1	—	(19)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (5)	$ —	$ —	$ —	$ (5)
Revenues	(39)	20	(1)	—	(20)
Other Operating Expense	—	(22)	—	—	(22)

	Nine Months Ended September 30				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
			(In millions)		
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$ (6)	$ —	$ —	$ —	$ (6)
2011					
Gain Recognized in AOCI (Effective Portion)	$ 4	$ —	$ 1	$ —	$ 5
Effective Gain (Loss) Reclassified to:					
Purchased Power Expense	16	—	—	—	16
Revenues	(12)	—	—	—	(12)
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain Recognized in:					
Other Operating Expense	$ 69	$ 12	$ —	$ 3	$ 84
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (248)	$ —	$ —	$ —	$ (248)
Revenues	260	18	—	—	278
Other Operating Expense	—	(51)	—	—	(51)
Fuel Expense	—	—	—	2	2
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$ 88	$ —	$ —	$ —	$ 88
Revenues	(1)	—	—	—	(1)
Other Operating Expense	(65)	2	2	—	(61)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$ (41)	$ —	$ —	$ —	$ (41)
Revenues	(69)	36	(2)	—	(35)
Other Operating Expense	—	(77)	—	—	(77)

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

Three Months Ended September 30				
NUGs	LCAPP	Regulated FTRs	Other	Total
		(In millions)		

Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	LCAPP	Regulated FTRs	Other	Total
2012					
Unrealized Gain (Loss) on Derivative Instrument	$ (50)	$ 3	$ —	$ —	$ (47)
Realized Gain (Loss) on Derivative Instrument	61	—	(1)	—	60
2011					
Unrealized Loss on Derivative Instrument	$ (89)	$ —	$ (3)	$ —	$ (92)
Realized Gain (Loss) on Derivative Instrument	53	—	(3)	—	50

	Nine Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
			(In millions)		
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Loss on Derivative Instrument	$(183)	$ (142)	$ —	$ —	$(325)
Realized Gain on Derivative Instrument	194	—	7	—	201
2011					
Unrealized Loss on Derivative Instrument	$(325)	$ —	$ —	$ —	$(325)
Realized Gain (Loss) on Derivative Instrument	187	—	(4)	(10)	173

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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 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 July 1, 2012	$ (293)	$ (145)	$ —	$ —	$ (438)
Additions/Change in value of existing contracts	(50)	3	—	—	(47)
Settled contracts	61	—	(1)	—	60
Outstanding net asset (liability) as of September 30, 2012	$ (282)	$ (142)	$ (1)	$ —	$ (425)
Outstanding net asset (liability) as of July 1, 2011	$ (447)	$ —	$ 2	$ —	$ (445)
Additions/Change in value of existing contracts	(89)	—	(3)	—	(92)
Settled contracts	53	—	(3)	—	50
Outstanding net asset (liability) as of September 30, 2011	$ (483)	$ —	$ (4)	$ —	$ (487)

	Nine Months Ended September 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 January 1, 2012	$ (293)	$ —	$ (8)	$ —	$ (301)
Additions/Change in value of existing contracts	(183)	(142)	—	—	(325)
Settled contracts	194	—	7	—	201

Outstanding net asset (liability) as of September 30, 2012	$ (282)	$ (142)	$ (1)	$ —	$ (425)
Outstanding net asset (liability) as of January 1, 2011	$ (345)	$ —	$ —	$ 10	$ (335)
Additions/Change in value of existing contracts	(325)	—	—	—	(325)
Settled contracts	187	—	(4)	(10)	173
Outstanding net asset (liability) as of September 30, 2011	$ (483)	$ —	$ (4)	$ —	$ (487)

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

Commitments, Guarantees and Contingencies (Tables)	9 Months Ended Sep. 30, 2012
Commitments and Contingencies Disclosure [Abstract]	
Schedule of Guarantor Obligations	The following table discloses the additional credit contingent contractual obligations as of September 30, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 397	$ 6	$ 42	$ 445
BB+/Ba1 Credit Ratings	$ 450	$ 6	$ 61	$ 517
Full impact of credit contingent contractual obligations	$ 671	$ 72	$ 76	$ 819

Organization and Basis of Presentation	9 Months Ended Sep. 30, 2012
Organization, Consolidation and Presentation of Financial Statements [Abstract]	
ORGANIZATION AND BASIS OF PRESENTATION	

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 nine months ended September 30, 2011, include just seven 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 nine months ended September 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.