Hanesbrands Inc.
Form 4
February 06, 2008

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL
OMB Number: 3235-0287
Expires: January 31, 2005
Estimated average burden hours per response... 0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
WYATT E LEE

(Last) (First) (Middle)

1000 EAST HANES MILL ROAD

(Street)

WINSTON-SALEM, NC 27105

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
Hanesbrands Inc. [HBI]

3. Date of Earliest Transaction (Month/Day/Year)
02/04/2008

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
EVP, CFO

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	02/04/2008		A		23,307 (1)	A	$ 0	160,567	D	
Common Stock								14	I	By 401(k) plan

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Employee Stock Option (right to buy)	$ 25.1	02/04/2008		A		82,979		(2)	02/04/2015	Common Stock	82,979

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
WYATT E LEE 1000 EAST HANES MILL ROAD WINSTON-SALEM, NC 27105			EVP, CFO	

Signatures

Catherine Meeker, attorney-in-fact	02/06/2008
**Signature of Reporting Person	Date

Explanation of Responses:

- * If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).
- ** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).
- **(1)** Consists of restricted stock units that upon vesting are settled on a one-for-one basis in shares of common stock, vesting in three installments of 33% on February 4, 2009, 33% on February 4, 2010 and 34% on February 4, 2011.
- **(2)** The options vest in three installments of 33% on February 4, 2009, 33% on February 4, 2010 and 34% on February 4, 2011.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. e="font-family:inherit;font-size:10pt;">

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-

Explanation of Responses:

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.

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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.

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

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2012	2011	2012	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.

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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.

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

	Nine Months Ended September 30	
(In millions)	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)

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:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	Three Months Ended September 30		Nine Months Ended September 30	
	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)

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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

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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.

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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.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and LCAPP contracts 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 (in millions)	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
January 1, 2011 Balance	$122	$(466)	$(344)	$—	$—	$—	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—	—	—	—
Unrealized gain (loss)	(58)	(144)	(202)	—	—	—	2	(27)	(25)
Purchases	—	—	—	—	—	—	13	(4)	9
Issuances	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	(7)	261	254	—	—	—	(14)	20	6
Transfers in (out) of Level 3	—	—	—	—	—	—	—	(12)	(12)
December 31, 2011 Balance	$57	$(349)	$(292)	$—	$—	$—	$1	$(23)	$(22)
Realized gain (loss)	—	—	—	—	—	—	—	—	—
Unrealized gain (loss)	(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

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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)

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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.

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Rollforward of Level 3 Measurements

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

	NUG Contracts[1]			LCAPP Contracts[1]		
	Derivative Assets (in millions)	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
January 1, 2011 Balance	$6	$(233)	$(227)	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—
Unrealized gain (loss)	(2)	(11)	(13)	—	—	—
Purchases	—	—	—	—	—	—
Issuances	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	97	97	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
December 31, 2011 Balance	$4	$(147)	$(143)	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—
Unrealized gain (loss)	(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.

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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

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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

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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	Fair Value September 30, 2012 (In millions)	December 31, 2011	Derivative Liabilities	Fair Value September 30, 2012 (In millions)	December 31, 2011
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 (In millions)	Sales	Net	Units
Power Contracts	33	38	(5)	MWH
FTRs	67	—	67	MWH
NUGs	16	—	16	MWH
LCAPP	408	—	408	MW
Natural Gas	16	—	16	BTUs

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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 (In millions)	FTRs	Interest Rate Swaps	Other	Total
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 (In millions)	FTRs	Interest Rate Swaps	Other	Total
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)

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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

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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

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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.

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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

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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.

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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

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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

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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

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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)
	(11)	(2)	(9)	11	(11)

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

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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

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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

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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

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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

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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

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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.

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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

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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.

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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

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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

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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)

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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	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	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)

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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 2012	2011	Increase (Decrease)
	(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	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	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

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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

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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	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	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.

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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.

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- 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 2012	2011	Increase (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 2012	2011	Increase (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

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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:

Operating Expenses (Credits) - Allegheny[1]	Nine Months Ended September 30 2012	2011	Increase (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).

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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.

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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 (In millions)	Available Liquidity
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 (In millions)	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations		Debt to Capitalization
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.

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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) (In millions)	LOC Termination Date	Reimbursements of LOC Draws Due
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

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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:

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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)

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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	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

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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.

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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	

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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.

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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.

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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.

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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

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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)