CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-Q
November 01, 2011
Table of Contents

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

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

For the quarterly period ended September 30, 2011

OR

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

For the transition period from ____________________ to ____________________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
000-53742	FIRSTENERGY SOLUTIONS CORP. (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	31-1560186
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308	34-0150020

	Telephone (800)736-3402	
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-4375005
1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY (A New Jersey Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	21-0485010
1-446	METROPOLITAN EDISON COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	23-0870160
1-3522	PENNSYLVANIA ELECTRIC COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	25-0718085

Table of Contents

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o	FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o	FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer þ	FirstEnergy Corp.
Accelerated Filer o	N/A
Non-accelerated Filer (Do not check if a smaller reporting company) þ	FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company
Smaller Reporting Company o	N/A

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

Yes o No þ	FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF OCTOBER 31, 2011
FirstEnergy Corp., $.10 par value	418,216,437
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
The Cleveland Electric Illuminating Company, no par value	67,930,743
The Toledo Edison Company, $5 par value	29,402,054
Jersey Central Power & Light Company, $10 par value	13,628,447
Metropolitan Edison Company, no par value	740,905
Pennsylvania Electric Company, $20 par value	4,427,577

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company common stock.

This combined Form 10-Q is separately filed by FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to any of the FirstEnergy subsidiary registrants is also attributed to FirstEnergy Corp.

FirstEnergy Web Site

Each of the registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through FirstEnergy's Internet web site at www.firstenergycorp.com.

These reports are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post important information on FirstEnergy's Internet web site and recognize FirstEnergy's Internet web site as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy's Internet web site shall not be deemed incorporated into, or to be part of, this report.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

Table of Contents

Forward-Looking Statements: This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry.
- The impact of the regulatory process on the pending matters in the various states in which we do business including, but not limited to, matters related to rates.
- The status of the PATH project in light of PJM's direction to suspend work on the project pending review of its planning process, its re-evaluation of the need for the project and the uncertainty of the timing and amounts of any related capital expenditures.
- Business and regulatory impacts from ATSI's realignment into PJM Interconnection, L.L.C.
- Economic or weather conditions affecting future sales and margins.
- Changes in markets for energy services.
- Changing energy and commodity market prices and availability.
- Financial derivative reforms that could increase our liquidity needs and collateral costs.
- The continued ability of FirstEnergy's regulated utilities to collect transition and other costs.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water intake and coal combustion residual regulations, the potential impacts of any laws, rules or regulations that ultimately replace CAIR, including CSAPR, and the effects of the EPA's recently released MACT proposal to establish certain mercury and other emission standards for electric generating units.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units).
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC including as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues that could delay the current outage at Davis-Besse for the installation of the new reactor vessel head, including indications of cracking in the plant's shield building currently under investigation.
- Adverse legal decisions and outcomes related to Met-Ed's and Penelec's ability to recover certain transmission costs through their transmission service charge riders.
- The continuing availability of generating units and changes in their ability to operate at or near full capacity.
- Replacement power costs being higher than anticipated or inadequately hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency mandates.
- The ability to accomplish or realize anticipated benefits from strategic goals.
- FirstEnergy's ability to improve electric commodity margins and the impact of, among other factors, the increased cost of coal and coal transportation on such margins.
- The ability to experience growth in the distribution business.
- The changing market conditions that could affect the value of assets held in FirstEnergy's nuclear decommissioning trusts, pension trusts and other trust funds, and cause FirstEnergy and its subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
-

The ability to access the public securities and other capital and credit markets in accordance with FirstEnergy's financing plan, the cost of such capital and overall condition of the capital and credit markets affecting FirstEnergy and its subsidiaries.

- Changes in general economic conditions affecting FirstEnergy and its subsidiaries.
- Interest rates and any actions taken by credit rating agencies that could negatively affect FirstEnergy's and its subsidiaries' access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- The continuing uncertainty of the national and regional economy and its impact on FirstEnergy's and its subsidiaries' major industrial and commercial customers.
- Issues concerning the soundness of financial institutions and counterparties with which FirstEnergy and its subsidiaries do business.
- Issues arising from the recently completed merger of FirstEnergy and Allegheny Energy, Inc. and the ongoing coordination of their combined operations including FirstEnergy's ability to maintain relationships with customers, employees and suppliers, as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.
- The risks and other factors discussed from time to time in the registrants' SEC filings, and other similar factors.

Dividends declared from time to time on FirstEnergy's common stock during any annual period may in aggregate vary from the

Table of Contents

indicated amount due to circumstances considered by FirstEnergy’s Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrants’ business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events or otherwise.

Table of Contents

TABLE OF CONTENTS

Table of Contents

TABLE OF CONTENTS (Continued)

Table of Contents

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011
AESC	Allegheny Energy Service Corporation, a subsidiary of AE
AE Supply	Allegheny Energy Supply Company LLC, an unregulated generation subsidiary of AE
AET	Allegheny Energy Transmission, LLC, a parent of TrAIL and PATH
AGC	Allegheny Generating Company, a generation subsidiary of AE
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
AVE	Allegheny Ventures, Inc.
ATSI	American Transmission Systems, Incorporated, which owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
Global Rail	A joint venture between FEV and WMB Loan Ventures II LLC, that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, that merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
Merger Sub	Element Merger Sub, Inc., a Maryland corporation and a wholly owned subsidiary of FirstEnergy
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary of AE
NGC	FirstEnergy Nuclear Generation Corp., which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline LLC, a joint venture between Allegheny and a subsidiary of AEP
PATH-VA	PATH Allegheny Virginia Transmission Corporation
PE	The Potomac Edison Company, a Maryland electric operating subsidiary of AE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	Met-Ed, Penelec, Penn and WP
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FEV, WMB Loan Ventures LLC and Gunvor Group, Ltd. that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company

Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec, MP, PE and WP
Utility Registrants	OE, CEI, TE, JCP&L, Met-Ed and Penelec
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary of AE

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

ALJ	Administrative Law Judge
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCL	Accumulated Other Comprehensive Loss
AEP	American Electric Power Company, Inc.
AQC	Air Quality Control
ARO	Asset Retirement Obligation
ARR	Auction Revenue Rights

Table of Contents

GLOSSARY OF TERMS, Continued

ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BMP	Bruce Mansfield Plant
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFL	Compact Florescent Light-bulb
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
CWA	Clean Water Act
CWIP	Construction Work in Progress
DCPD	Deferred Compensation Plan for Outside Directors
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPA	Department of the Public Advocate, Division of Rate Counsel (New Jersey)
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EIS	Energy Insurance Services, Inc.
EMP	Energy Master Plan
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FRR	Fixed Resource Requirement
FTRs	Financial Transmission Rights
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
ICG	International Coal Group inc.
IRS	Internal Revenue Service
JOA	Joint Operating Agreement
kV	Kilovolt
KWH	Kilowatt-hours

LBR	Little Blue Run
LED	Light-Emitting Diode
LiDAR	Light Detection and Ranging
LOC	Letter of Credit
LSE	Load Serving Entity

Table of Contents

GLOSSARY OF TERMS, Continued

LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MSHA	Mine Safety and Health Administration
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatts
MWH	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trusts
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NNSR	Non-Attainment New Source Review
NOAC	Northwest Ohio Aggregation Coalition
NOPEC	Northeast Ohio Public Energy Council
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
NYPSC	New York State Public Service Commission
NYSEG	New York State Electric and Gas
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OVEC	Ohio Valley Electric Corporation
PAD	Pre-application Document
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PICA	Pennsylvania Intergovernmental Cooperation Authority
PJM	PJM Interconnection L. L. C.
POLR	Provider of Last Resort; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978

RECs	Renewable Energy Credits
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
Rider DCR	Delivery Capital Recovery Rider

Table of Contents

GLOSSARY OF TERMS, Continued

ROE	Return on Equity
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Service
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SRECs	Solar Renewable Energy Credits
TBC	Transition Bond Charge
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
TSC	Transmission Service Charge
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

Table of Contents

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
In millions, except per share amounts	2011	2010	2011	2010
REVENUES:				
Electric utilities	$3,041	$2,757	$7,966	$7,673
Unregulated businesses	1,678	971	4,389	2,495
Total revenues*	4,719	3,728	12,355	10,168
OPERATING EXPENSES:				
Fuel	632	400	1,720	1,084
Purchased power	1,349	1,319	3,755	3,620
Other operating expenses	1,024	738	3,130	2,112
Provision for depreciation	292	182	794	565
Amortization of regulatory assets	122	176	344	549
General taxes	269	206	748	587
Impairment of long-lived assets	9	292	41	294
Total operating expenses	3,697	3,313	10,532	8,811
OPERATING INCOME	1,022	415	1,823	1,357
OTHER INCOME (EXPENSE):				
Investment income	48	46	100	93
Interest expense	(267)	(208)	(763)	(628)
Capitalized interest	17	41	55	122
Total other expense	(202)	(121)	(608)	(413)
INCOME BEFORE INCOME TAXES	820	294	1,215	944
INCOME TAXES	311	119	490	364
NET INCOME	509	175	725	580
Loss attributable to noncontrolling interest	(2)	(4)	(17)	(19)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$511	$179	$742	$599
EARNINGS PER SHARE OF COMMON STOCK:				
Basic	$1.22	$0.59	$1.89	$1.97
Diluted	$1.22	$0.59	$1.88	$1.96
AVERAGE SHARES OUTSTANDING:				
Basic	418	304	392	304
Diluted	420	305	394	305
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$1.10	$1.10	$1.65	$1.65

* Includes excise tax collections of $137 million and $120 million in the three months ended September 30, 2011 and 2010, respectively, and $371 million and $328 million in the nine months ended September 30, 2011 and 2010,

respectively.

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

1

Table of Contents

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2011	2010	2011	2010
NET INCOME	$509	$175	$725	$580
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits	15	17	145	47
Unrealized gain on derivative hedges	2	6	13	16
Change in unrealized gain on available-for-sale securities	(26)	20	(7)	32
Other comprehensive income (loss)	(9)	43	151	95
Income taxes (benefits) on other comprehensive income (loss)	(6)	14	48	30
Other comprehensive income (loss), net of tax	(3)	29	103	65
COMPREHENSIVE INCOME	506	204	828	645
COMPREHENSIVE LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST	(2)	(4)	(17)	(19)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$508	$208	$845	$664

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

2

Table of Contents

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$291	$1,019
Receivables-		
Customers, net of allowance for uncollectible accounts of $37 in 2011 and $36 in 2010	1,633	1,392
Other, net of allowance for uncollectible accounts of $9 in 2011 and $8 in 2010	247	176
Materials and supplies, at average cost	822	638
Prepaid taxes	214	199
Derivatives	195	182
Other	189	92
	3,591	3,698
ASSETS PENDING SALE (Note 15)	402	—
PROPERTY, PLANT AND EQUIPMENT:		
In service	39,350	29,451
Less — Accumulated provision for depreciation	11,803	11,180
	27,547	18,271
Construction work in progress	1,720	1,517
	29,267	19,788
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,060	1,973
Investments in lease obligation bonds	414	476
Nuclear fuel disposal trust	218	208
Other	440	345
	3,132	3,002
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,448	5,575
Regulatory assets	2,160	1,826
Intangible assets	910	256
Other	751	660
	10,269	8,317
	$46,661	$34,805
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,840	$1,486
Short-term borrowings	—	700
Accounts payable	1,009	872
Accrued taxes	482	326
Accrued compensation and benefits	350	315
Derivatives	202	266
Other	980	733

	4,863	4,698
LIABILITIES RELATED TO ASSETS PENDING SALE (Note 15)	401	—
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 and 375,000,000 shares, respectively- 418,216,437 and 304,835,407 shares outstanding, respectively	42	31
Other paid-in capital	9,782	5,444
Accumulated other comprehensive loss	(1,436)	(1,539)
Retained earnings	4,658	4,609
Total common stockholders' equity	13,046	8,545
Noncontrolling interest	(31)	(32)
Total equity	13,015	8,513
Long-term debt and other long-term obligations	15,823	12,579
	28,838	21,092
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	5,315	2,879
Retirement benefits	2,045	1,868
Asset retirement obligations	1,473	1,407
Deferred gain on sale and leaseback transaction	934	959
Adverse power contract liability	665	466
Other	2,127	1,436
	12,559	9,015
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$46,661	$34,805

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

3

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In millions)	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$725	$580
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	794	565
Amortization of regulatory assets	344	549
Nuclear fuel and lease amortization	152	123
Deferred purchased power and other costs	(222)	(192)
Deferred income taxes and investment tax credits, net	636	259
Deferred rents and lease market valuation liability	(17)	(21)
Accrued compensation and retirement benefits	95	48
Commodity derivative transactions, net	(22)	(40)
Pension trust contributions	(375)	—
Asset impairments	59	315
Cash collateral paid, net	(66)	(54)
Interest rate swap transactions	—	129
Gain on investment securities held in trusts	(56)	(39)
Decrease (increase) in operating assets-		
Receivables	139	(172)
Materials and supplies	62	(6)
Prepayments and other current assets	(1)	(4)
Increase (decrease) in operating liabilities-		
Accounts payable	(154)	(16)
Accrued taxes	20	(18)
Accrued interest	67	63
Other	49	4
Net cash provided from operating activities	2,229	2,073
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	603	251
Redemptions and Repayments-		
Long-term debt	(1,581)	(422)
Short-term borrowings, net	(700)	(171)
Common stock dividend payments	(651)	(503)
Other	(73)	(25)
Net cash used for financing activities	(2,402)	(870)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,529)	(1,467)
Proceeds from asset sales	519	117
Sales of investment securities held in trusts	3,678	2,577
Purchases of investment securities held in trusts	(3,801)	(2,610)
Customer acquisition costs	(2)	(110)
Cash investments	51	56
Cash received in Allegheny merger	590	—

Other	(61)	(8)
Net cash used for investing activities	(555)	(1,445)
Net change in cash and cash equivalents	(728)	(242)
Cash and cash equivalents at beginning of period	1,019	874
Cash and cash equivalents at end of period	$291	$632
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction: merger with Allegheny, common stock issued	$4,354	$—

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

4

Table of Contents

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

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales to non-affiliates	$1,251	$951	$3,348	$2,348
Electric sales to affiliates	143	600	574	1,746
Other	73	38	229	209
Total revenues	1,467	1,589	4,151	4,303
OPERATING EXPENSES:				
Fuel	386	391	1,045	1,062
Purchased power from affiliates	55	116	189	246
Purchased power from non-affiliates	328	446	954	1,206
Other operating expenses	405	308	1,315	916
Provision for depreciation	69	60	205	186
General taxes	31	22	91	71
Impairment of long-lived assets	2	292	22	294
Total operating expenses	1,276	1,635	3,821	3,981
OPERATING INCOME (LOSS)	191	(46)	330	322
OTHER INCOME (EXPENSE):				
Investment income	28	30	50	44
Miscellaneous income (expense)	9	3	17	10
Interest expense — affiliates	(2)	(2)	(5)	(7)
Interest expense — other	(51)	(50)	(156)	(151)
Capitalized interest	8	23	28	67
Total other income (expense)	(8)	4	(66)	(37)
INCOME (LOSS) BEFORE INCOME TAXES	183	(42)	264	285
INCOME TAXES (BENEFITS)	73	(5)	98	108
NET INCOME (LOSS)	110	(37)	166	177
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits	1	1	4	(8)
Unrealized gain (loss) on derivative hedges	(1)	3	4	7
Change in unrealized gain on available-for-sale securities	(22)	18	(7)	29
Other comprehensive income (loss)	(22)	22	1	28
Income taxes (benefits) on other comprehensive income (loss)	(9)	8	(1)	10
Other comprehensive income (loss), net of tax	(13)	14	2	18

COMPREHENSIVE INCOME (LOSS)	$97	$(23)	$168	$195

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

Table of Contents

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$6	$9
Receivables-		
Customers, net of allowance for uncollectible accounts of $19 in 2011 and $17 in 2010	452	366
Affiliated companies	478	478
Other, net of allowances for uncollectible accounts of $3 in 2011 and $7 in 2010	61	90
Notes receivable from affiliated companies	340	397
Materials and supplies, at average cost	477	545
Derivatives	170	182
Prepayments and other	61	59
	2,045	2,126
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,440	11,321
Less — Accumulated provision for depreciation	4,314	4,024
	7,126	7,297
Construction work in progress	818	1,063
	7,944	8,360
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,187	1,146
Other	10	12
	1,197	1,158
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	126	134
Goodwill	24	24
Property taxes	41	41
Unamortized sale and leaseback costs	68	73
Derivatives	136	98
Other	83	48
	478	418
	$11,664	$12,062
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$877	$1,132
Short-term borrowings-		
Affiliated companies	—	12
Accounts payable-		
Affiliated companies	425	467
Other	170	241
Derivatives	175	266
Other	323	322
	1,970	2,440
CAPITALIZATION:		

Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,492	1,490
Accumulated other comprehensive loss	(118)	(120)
Retained earnings	2,584	2,418
Total common stockholder's equity	3,958	3,788
Long-term debt and other long-term obligations	2,892	3,181
	6,850	6,969
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	934	959
Accumulated deferred income taxes	303	58
Asset retirement obligations	889	892
Retirement benefits	299	285
Lease market valuation liability	183	217
Derivatives	67	81
Other	169	161
	2,844	2,653
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$11,664	$12,062

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

Table of Contents

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In millions)	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$166	$177
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	205	186
Nuclear fuel and lease amortization	151	126
Deferred rents and lease market valuation liability	(37)	(41)
Deferred income taxes and investment tax credits, net	229	96
Asset impairments	40	315
Accrued compensation and retirement benefits	16	16
Gain on investment securities held in trusts	(48)	(34)
Commodity derivative transactions, net	(54)	(40)
Cash collateral paid, net	(81)	(54)
Decrease (increase) in operating assets-		
Receivables	(34)	(91)
Materials and supplies	72	(15)
Prepayments and other current assets	8	36
Increase (decrease) in operating liabilities-		
Accounts payable	(113)	(50)
Accrued taxes	24	(8)
Other	(7)	5
Net cash provided from operating activities	537	624
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	247	250
Redemptions and repayments-		
Long-term debt	(791)	(296)
Short-term borrowings, net	(12)	—
Other	(10)	(1)
Net cash used for financing activities	(566)	(47)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(473)	(801)
Proceeds from asset sales	519	117
Sales of investment securities held in trusts	1,613	1,478
Purchases of investment securities held in trusts	(1,654)	(1,511)
Loans to affiliated companies, net	57	303
Customer acquisition costs	(2)	(110)
Leasehold improvement payments to affiliated companies	—	(51)
Other	(34)	(2)
Net cash provided from (used for) investing activities	26	(577)

Net change in cash and cash equivalents	(3)	—
Cash and cash equivalents at beginning of period	9	—
Cash and cash equivalents at end of period	$6	$—

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

Table of Contents

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

(In millions)	Three Months Ended September 30 2011	Three Months Ended September 30 2010	Nine Months Ended September 30 2011	Nine Months Ended September 30 2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$441	$457	$1,165	$1,352
Excise and gross receipts tax collections	29	30	82	82
Total revenues	470	487	1,247	1,434
OPERATING EXPENSES:				
Purchased power from affiliates	57	137	220	425
Purchased power from non-affiliates	80	84	203	257
Other operating expenses	119	95	331	272
Provision for depreciation	23	22	67	66
Amortization of regulatory assets, net	46	10	49	48
General taxes	51	49	146	140
Total operating expenses	376	397	1,016	1,208
OPERATING INCOME	94	90	231	226
OTHER INCOME (EXPENSE):				
Investment income	10	5	19	17
Miscellaneous income	1	2	1	2
Interest expense	(22)	(22)	(66)	(66)
Capitalized interest	—	—	1	1
Total other expense	(11)	(15)	(45)	(46)
INCOME BEFORE INCOME TAXES	83	75	186	180
INCOME TAXES	33	29	67	61
NET INCOME	50	46	119	119
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	2	1	3	5
Change in unrealized gain on available-for-sale securities	(3)	2	(1)	3
Other comprehensive income	(1)	3	2	8
Income taxes (benefits) on other comprehensive income	(1)	1	(2)	1
Other comprehensive income, net of tax	—	2	4	7
COMPREHENSIVE INCOME	$50	$48	$123	$126

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

Table of Contents

OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$—	$420
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2011 and 2010	177	177
Affiliated companies	76	118
Other	30	12
Notes receivable from affiliated companies	180	17
Prepayments and other	36	7
	499	751
UTILITY PLANT:		
In service	3,206	3,137
Less — Accumulated provision for depreciation	1,241	1,208
	1,965	1,929
Construction work in progress	78	45
	2,043	1,974
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	178	190
Nuclear plant decommissioning trusts	136	127
Other	91	96
	405	413
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	343	400
Pension assets	66	29
Property taxes	71	71
Unamortized sale and leaseback costs	26	30
Other	16	18
	522	548
	$3,469	$3,686
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1	$1
Short-term borrowings-		
Affiliated companies	—	142
Other	—	1
Accounts payable-		
Affiliated companies	100	99
Other	36	30
Accrued taxes	79	79
Accrued interest	25	25
Other	112	75
	353	452
CAPITALIZATION:		
Common stockholder's equity-		

Common stock, without par value, authorized 175,000,000 shares – 60 shares outstanding	785	952
Accumulated other comprehensive loss	(175)	(179)
Retained earnings	160	141
Total common stockholder's equity	770	914
Noncontrolling interest	6	6
Total equity	776	920
Long-term debt and other long-term obligations	1,146	1,152
	1,922	2,072
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	751	696
Accumulated deferred investment tax credits	9	10
Retirement benefits	184	184
Asset retirement obligations	70	75
Other	180	197
	1,194	1,162
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$3,469	$3,686

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

Table of Contents

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$119	$119
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	67	66
Amortization of regulatory assets, net	49	48
Purchased power cost recovery reconciliation	(9)	4
Amortization of lease costs	28	28
Deferred income taxes and investment tax credits, net	67	8
Accrued compensation and retirement benefits	(10)	(17)
Cash collateral from suppliers, net	1	23
Pension trust contribution	(27)	—
Decrease (increase) in operating assets-		
Receivables	50	92
Prepayments and other current assets	(30)	10
Decrease in operating liabilities-		
Accounts payable	(23)	(87)
Accrued taxes	—	(26)
Other	2	(7)
Net cash provided from operating activities	284	261
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(1)	(10)
Short-term borrowings, net	(142)	(46)
Common stock dividend payments	(268)	(250)
Other	(2)	—
Net cash used for financing activities	(413)	(306)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(123)	(111)
Leasehold improvement payments from affiliated companies	—	18
Sales of investment securities held in trusts	154	79
Purchases of investment securities held in trusts	(161)	(84)
Loans to affiliated companies, net	(163)	102
Cash investments	12	12
Other	(10)	(7)
Net cash provided from (used for) investing activities	(291)	9
Net change in cash and cash equivalents	(420)	(36)
Cash and cash equivalents at beginning of period	420	324
Cash and cash equivalents at end of period	$—	$288

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

Table of Contents

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In thousands)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$225,218	$309,236	$634,108	$901,913
Excise tax collections	18,826	19,480	52,677	52,548
Total revenues	244,044	328,716	686,785	954,461
OPERATING EXPENSES:				
Purchased power from affiliates	25,076	89,389	107,284	298,204
Purchased power from non-affiliates	27,303	35,151	68,622	105,200
Other operating expenses	40,330	36,441	106,991	96,613
Provision for depreciation	18,478	18,057	55,392	54,504
Amortization of regulatory assets, net	23,077	45,136	64,613	121,082
General taxes	40,952	39,878	118,118	107,207
Total operating expenses	175,216	264,052	521,020	782,810
OPERATING INCOME	68,828	64,664	165,765	171,651
OTHER INCOME (EXPENSE):				
Investment income	5,669	6,604	17,903	20,756
Miscellaneous income	549	533	2,223	1,790
Interest expense	(32,240)	(33,384)	(97,453)	(100,267)
Capitalized interest	83	10	146	43
Total other expense	(25,939)	(26,237)	(77,181)	(77,678)
INCOME BEFORE INCOME TAXES	42,889	38,427	88,584	93,973
INCOME TAXES	16,282	13,479	26,927	33,107
NET INCOME	26,607	24,948	61,657	60,866
Income attributable to noncontrolling interest	309	366	984	1,151
EARNINGS AVAILABLE TO PARENT	$26,298	$24,582	$60,673	$59,715
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$26,607	$24,948	$61,657	$60,866
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits	2,969	3,228	8,911	(16,129)
Income taxes (benefits) on other comprehensive income	858	976	1,256	(6,325)
Other comprehensive income (loss), net of tax	2,111	2,252	7,655	(9,804)

COMPREHENSIVE INCOME	28,718	27,200	69,312	51,062
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	309	366	984	1,151
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$28,409	$26,834	$68,328	$49,911

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

Table of Contents

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$244	$238
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,169 in 2011 and $4,589 in 2010	99,752	183,744
Affiliated companies	20,962	77,047
Other	7,077	11,544
Notes receivable from affiliated companies	110,999	23,236
Materials and supplies, at average cost	18,118	398
Prepayments and other	5,208	3,258
	262,360	299,465
UTILITY PLANT:		
In service	2,434,038	2,396,893
Less — Accumulated provision for depreciation	950,395	932,246
	1,483,643	1,464,647
Construction work in progress	64,139	38,610
	1,547,782	1,503,257
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	286,814	340,029
Other	10,035	10,074
	296,849	350,103
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	290,556	370,403
Pension assets	15,240	—
Property taxes	80,614	80,614
Other	12,826	11,486
	2,087,757	2,151,024
	$4,194,748	$4,303,849
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$202	$161
Short-term borrowings from affiliated companies	23,303	105,996
Accounts payable-		
Affiliated companies	24,236	32,020
Other	13,271	14,947
Accrued taxes	76,256	84,668
Accrued interest	39,253	18,555
Other	41,058	44,569
	217,579	300,916
CAPITALIZATION:		
Common stockholder's equity-		
	889,221	887,087

Common stock, without par value, authorized 105,000,000 shares - 67,930,743 shares outstanding		
Accumulated other comprehensive loss	(145,532)	(153,187)
Retained earnings	565,578	568,906
Total common stockholder's equity	1,309,267	1,302,806
Noncontrolling interest	14,886	18,017
Total equity	1,324,153	1,320,823
Long-term debt and other long-term obligations	1,831,032	1,852,530
	3,155,185	3,173,353
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	636,842	622,771
Accumulated deferred investment tax credits	10,363	10,994
Retirement benefits	77,526	95,654
Other	97,253	100,161
	821,984	829,580
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$4,194,748	$4,303,849

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

Table of Contents

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In thousands)	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$61,657	$60,866
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	55,392	54,504
Amortization of regulatory assets, net	64,613	121,082
Deferred income taxes and investment tax credits, net	13,184	(24,283)
Accrued compensation and retirement benefits	9,371	10,467
Accrued regulatory obligations	(2,621)	(1,897)
Cash collateral from suppliers, net	1,918	19,245
Pension trust contribution	(35,000)	—
Decrease (increase) in operating assets-		
Receivables	158,811	86,725
Prepayments and other current assets	(19,670)	5,421
Increase (decrease) in operating liabilities-		
Accounts payable	(22,119)	(57,272)
Accrued taxes	(8,412)	(23,876)
Accrued interest	20,698	20,795
Other	791	2,637
Net cash provided from operating activities	298,613	274,414
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(116)	(84)
Short-term borrowings, net	(104,228)	(230,132)
Common stock dividend payments	(64,000)	(100,000)
Other	(5,873)	(4,100)
Net cash used for financing activities	(174,217)	(334,316)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(80,445)	(70,812)
Loans to affiliated companies, net	(87,763)	2,897
Redemption of lessor notes	53,215	48,610
Other	(9,397)	(6,776)
Net cash used for investing activities	(124,390)	(26,081)
Net change in cash and cash equivalents	6	(85,983)
Cash and cash equivalents at beginning of period	238	86,230
Cash and cash equivalents at end of period	$244	$247

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

13

Table of Contents

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In thousands)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$136,766	$136,058	$336,139	$376,180
Excise tax collections	8,023	7,979	21,595	21,079
Total revenues	144,789	144,037	357,734	397,259
OPERATING EXPENSES:				
Purchased power from affiliates	15,834	42,338	68,388	144,062
Purchased power from non-affiliates	22,182	16,663	52,284	50,377
Other operating expenses	35,545	28,746	104,681	79,790
Provision for depreciation	7,969	7,800	23,859	23,763
Amortization of regulatory assets, net	18,143	6,591	(389)	(3,708)
General taxes	14,284	14,023	41,174	39,766
Total operating expenses	113,957	116,161	289,997	334,050
OPERATING INCOME	30,832	27,876	67,737	63,209
OTHER INCOME (EXPENSE):				
Investment income	2,919	3,018	8,440	11,875
Miscellaneous income (expense)	417	(502)	(816)	(2,853)
Interest expense	(10,520)	(10,479)	(31,378)	(31,421)
Capitalized interest	161	94	398	252
Total other expense	(7,023)	(7,869)	(23,356)	(22,147)
INCOME BEFORE INCOME TAXES	23,809	20,007	44,381	41,062
INCOME TAXES	8,971	6,911	12,135	13,241
NET INCOME	14,838	13,096	32,246	27,821
Income (loss) attributable to noncontrolling interest	1	(4)	5	1
EARNINGS AVAILABLE TO PARENT	$14,837	$13,100	$32,241	$27,820
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$14,838	$13,096	$32,246	$27,821
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	577	713	1,744	1,723
Increase (decrease) in unrealized gain on available-for-sale securities	(1,328)	427	731	466
Other comprehensive income (loss)	(751)	1,140	2,475	2,189
	(394)	330	291	565

Income taxes (benefits) on other comprehensive income (loss)				
Other comprehensive income (loss), net of tax	(357)	810	2,184	1,624
COMPREHENSIVE INCOME	14,481	13,906	34,430	29,445
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO NONCONTROLLING INTEREST	1	(4)	5	1
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$14,480	$13,910	$34,425	$29,444

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

Table of Contents

THE TOLEDO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$14	$149,262
Receivables-		
Customers, net of allowance for uncollectible accounts of $1,550 in 2011 and $1 in 2010	52,892	29
Affiliated companies	20,694	31,777
Other, net of allowance for uncollectible accounts of $257 in 2011 and $330 in 2010	2,715	18,464
Notes receivable from affiliated companies	187,765	96,765
Prepayments and other	13,849	2,306
	277,929	298,603
UTILITY PLANT:		
In service	961,324	947,203
Less — Accumulated provision for depreciation	456,655	446,401
	504,669	500,802
Construction work in progress	19,150	12,604
	523,819	513,406
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	82,133	103,872
Nuclear plant decommissioning trusts	78,214	75,558
Other	1,450	1,492
	161,797	180,922
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	69,720	72,059
Pension assets	24,780	—
Property taxes	24,990	24,990
Other	27,661	23,750
	647,727	621,375
	$1,611,272	$1,614,306
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$—	$199
Accounts payable-		
Affiliated companies	17,045	17,168
Other	9,248	7,351
Accrued taxes	27,822	24,401
Accrued interest	15,983	5,931
Lease market valuation liability	36,900	36,900
Other	23,560	23,145
	130,558	115,095
CAPITALIZATION:		
Common stockholder's equity-		
	147,010	147,010

Common stock, $5 par value, authorized 60,000,000 shares - 29,402,054 shares outstanding		
Other paid-in capital	178,138	178,182
Accumulated other comprehensive loss	(47,000)	(49,183)
Retained earnings	115,775	117,534
Total common stockholder’s equity	393,923	393,543
Noncontrolling interest	2,594	2,589
Total equity	396,517	396,132
Long-term debt and other long-term obligations	597,609	600,493
	994,126	996,625
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	160,515	132,019
Accumulated deferred investment tax credits	5,607	5,930
Retirement benefits	52,585	71,486
Asset retirement obligations	30,237	28,762
Lease market valuation liability	171,625	199,300
Other	66,019	65,089
	486,588	502,586
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$1,611,272	$1,614,306

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

15

Table of Contents

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In thousands)	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$32,246	$27,821
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	23,859	23,763
Amortization of regulatory assets, net	(389)	(3,708)
Deferred rents and lease market valuation liability	(37,710)	(36,123)
Deferred income taxes and investment tax credits, net	32,850	18,927
Accrued compensation and retirement benefits	2,490	4,529
Pension trust contribution	(45,000)	—
Cash collateral from suppliers, net	1,013	9,874
Decrease (increase) in operating assets-		
Receivables	(24,683)	61,051
Prepayments and other current assets	(11,731)	2,839
Increase (decrease) in operating liabilities-		
Accounts payable	(4,714)	(69,846)
Accrued taxes	3,422	(6,172)
Accrued Interest	10,052	10,050
Other	6,332	(10,931)
Net cash provided from (used for) operating activities	(11,963)	32,074
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Short-term borrowings, net	—	(225,975)
Common stock dividend payments	(34,000)	(130,000)
Other	(1,893)	(279)
Net cash used for financing activities	(35,893)	(356,254)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(27,138)	(29,592)
Leasehold improvement payments from affiliated companies	—	32,829
Loans to affiliated companies, net	(91,000)	3,847
Redemption of lessor notes	21,739	20,509
Sales of investment securities held in trusts	79,703	118,360
Purchases of investment securities held in trusts	(81,878)	(119,777)
Other	(2,818)	(4,550)
Net cash provided from (used for) investing activities	(101,392)	21,626
Net change in cash and cash equivalents	(149,248)	(302,554)
Cash and cash equivalents at beginning of period	149,262	436,712
Cash and cash equivalents at end of period	$14	$134,158

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

Table of Contents

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)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$762	$952	$1,973	$2,353
Excise tax collections	15	16	39	39
Total revenues	777	968	2,012	2,392
OPERATING EXPENSES:				
Purchased power	429	557	1,127	1,381
Other operating expenses	132	89	297	259
Provision for depreciation	31	27	83	82
Amortization (deferral) of regulatory assets, net	(4)	100	118	252
General taxes	20	20	53	51
Total operating expenses	608	793	1,678	2,025
OPERATING INCOME	169	175	334	367
OTHER INCOME (EXPENSE):				
Miscellaneous income	4	2	8	5
Interest expense	(32)	(30)	(93)	(89)
Capitalized interest	1	—	2	—
Total other expense	(27)	(28)	(83)	(84)
INCOME BEFORE INCOME TAXES	142	147	251	283
INCOME TAXES	59	64	107	121
NET INCOME	83	83	144	162
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	4	4	13	24
Other comprehensive income	4	4	13	24
Income taxes on other comprehensive income	2	1	5	9
Other comprehensive income, net of tax	2	3	8	15
COMPREHENSIVE INCOME	$85	$86	$152	$177

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

Table of Contents

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

(In millions, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$—	$—
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2011 and 2010	296	323
Affiliated companies	14	54
Other	18	26
Notes receivable — affiliated companies	—	177
Prepaid taxes	70	11
Other	19	13
	417	604
UTILITY PLANT:		
In service	4,615	4,563
Less — Accumulated provision for depreciation	1,697	1,657
	2,918	2,906
Construction work in progress	139	63
	3,057	2,969
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	218	208
Nuclear plant decommissioning trusts	194	182
Other	2	2
	414	392
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	461	513
Other	35	28
	2,307	2,352
	$6,195	$6,317
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$33	$32
Short-term borrowings-		
Affiliated companies	312	—
Accounts payable-		
Affiliated companies	8	29
Other	134	158
Accrued compensation and benefits	36	35
Customer deposits	24	23
Accrued taxes	1	3
Accrued interest	30	18
Other	14	23
	592	321
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	2,509
Accumulated other comprehensive loss	(245)	(253)
Retained earnings	371	227
Total common stockholder’s equity	2,273	2,619
Long-term debt and other long-term obligations	1,746	1,770
	4,019	4,389
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	788	716
Power purchase contract liability	222	233
Nuclear fuel disposal costs	197	197
Retirement benefits	73	182
Asset retirement obligations	114	108
Other	190	171
	1,584	1,607
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10) 1		
	$6,195	$6,317

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

Table of Contents

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

(In millions)	Nine Months Ended September 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$144	$162
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	83	82
Amortization of regulatory assets, net	118	252
Deferred purchased power and other costs	(84)	(85)
Deferred income taxes and investment tax credits, net	77	15
Accrued compensation and retirement benefits	6	11
Cash collateral paid, net	—	(23)
Pension trust contribution	(105)	—
Decrease (increase) in operating assets-		
Receivables	85	(73)
Prepaid taxes	(59)	(37)
Increase (decrease) in operating liabilities-		
Accounts payable	(60)	(38)
Accrued taxes	(1)	35
Accrued interest	12	12
Other	11	(14)
Net cash provided from operating activities	227	299
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	312	—
Redemptions and Repayments-		
Long-term debt	(23)	(22)
Common stock dividend payments	—	(165)
Equity payment to parent	(500)	—
Other	(2)	—
Net cash used for financing activities	(213)	(187)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(160)	(130)
Loans to affiliated companies, net	177	39
Sales of investment securities held in trusts	610	340
Purchases of investment securities held in trusts	(624)	(353)
Other	(17)	(8)
Net cash used for investing activities	(14)	(112)
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 the Consolidated Financial Statements are an integral part of these financial statements.

Table of Contents

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

	Three Months Ended September 30		Nine Months Ended September 30	
(In thousands)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$299,784	$460,864	$903,563	$1,334,454
Gross receipts tax collections	16,589	23,049	49,990	65,245
Total revenues	316,373	483,913	953,553	1,399,699
OPERATING EXPENSES:				
Purchased power from affiliates	33,574	166,039	118,398	476,119
Purchased power from non-affiliates	127,765	87,561	381,644	264,765
Other operating expenses	47,490	141,761	144,797	333,895
Provision for depreciation	14,478	12,978	39,667	39,176
Amortization of regulatory assets, net	24,000	15,480	78,261	112,869
General taxes	19,268	25,029	58,570	66,663
Total operating expenses	266,575	448,848	821,337	1,293,487
OPERATING INCOME	49,798	35,065	132,216	106,212
OTHER INCOME (EXPENSE):				
Interest income	14	581	120	2,678
Miscellaneous income	1,400	1,539	3,285	5,093
Interest expense	(13,343)	(13,037)	(39,530)	(39,812)
Capitalized interest	251	176	626	461
Total other expense	(11,678)	(10,741)	(35,499)	(31,580)
INCOME BEFORE INCOME TAXES	38,120	24,324	96,717	74,632
INCOME TAXES	12,971	10,084	32,203	30,968
NET INCOME	25,149	14,240	64,514	43,664
OTHER COMPREHENSIVE INCOME				
Pension and other postretirement benefits	2,163	2,161	6,353	14,032
Unrealized gain on derivative hedges	83	84	251	252
Other comprehensive income	2,246	2,245	6,604	14,284
Income taxes on other comprehensive income	841	723	2,473	5,624
Other comprehensive income, net of tax	1,405	1,522	4,131	8,660
COMPREHENSIVE INCOME	$26,554	$15,762	$68,645	$52,324

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

20

Table of Contents

METROPOLITAN EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$157	$243,220
Receivables-		
Customers, net of allowance for uncollectible accounts of $3,191 in 2011 and $3,868 in 2010	143,962	178,522
Affiliated companies	10,130	24,920
Other	19,130	13,007
Notes receivable from affiliated companies	—	11,028
Prepaid taxes	9,981	343
Other	3,658	2,289
	187,018	473,329
UTILITY PLANT:		
In service	2,277,244	2,247,853
Less — Accumulated provision for depreciation	862,677	846,003
	1,414,567	1,401,850
Construction work in progress	50,559	23,663
	1,465,126	1,425,513
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	301,652	289,328
Other	854	884
	302,506	290,212
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	372,128	295,856
Power purchase contract asset	52,245	111,562
Other	51,389	31,699
	892,261	855,616
	$2,846,911	$3,044,670
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$28,500	$28,760
Short-term borrowings-		
Affiliated companies	282,199	124,079
Accounts payable-		
Affiliated companies	20,645	33,942
Other	42,685	29,862
Accrued taxes	7,734	60,856
Accrued interest	11,412	16,114
Other	31,451	29,278
	424,626	322,891
CAPITALIZATION:		
Common stockholder’s equity-		
Common stock, without par value, authorized 900,000 shares -	842,682	1,197,076

740,905 and 859,500 shares outstanding, respectively		
Accumulated other comprehensive loss	(138,252)	(142,383)
Retained earnings	71,920	32,406
Total common stockholder's equity	776,350	1,087,099
Long-term debt and other long-term obligations	699,747	718,860
	1,476,097	1,805,959
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	487,140	473,009
Nuclear fuel disposal costs	44,474	44,449
Asset retirement obligations	202,498	192,659
Retirement benefits	22,362	29,121
Power purchase contract liability	131,821	116,027
Other	57,893	60,555
	946,188	915,820
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$2,846,911	$3,044,670

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

Table of Contents

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Nine Months Ended September 30 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$64,514	$43,664
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	39,667	39,176
Amortization of regulatory assets, net	78,261	112,869
Deferred costs recoverable as regulatory assets	(65,278)	(49,646)
Deferred income taxes and investment tax credits, net	(1,006)	23,781
Accrued compensation and retirement benefits	276	(282)
Cash collateral from (to) suppliers, net	283	(17,647)
Pension trust contribution	(35,000)	—
Decrease (increase) in operating assets-		
Receivables	46,125	(18,444)
Prepaid taxes	(9,638)	(12,077)
Decrease in operating liabilities-		
Accounts payable	(4,161)	(18,763)
Accrued taxes	(52,430)	(8,203)
Accrued interest	(4,702)	(5,645)
Other	13,377	6,654
Net cash provided from operating activities	70,288	95,437
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	158,120	6,296
Redemptions and Repayments-		
Common stock	(150,000)	—
Long-term debt	(14,966)	(100,000)
Common stock dividend payments	(80,000)	—
Equity payment to parent	(150,000)	—
Net cash used for financing activities	(236,846)	(93,704)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(72,830)	(77,921)
Sales of investment securities held in trusts	807,405	420,116
Purchases of investment securities held in trusts	(815,489)	(427,150)
Loans to affiliated companies, net	11,028	85,949
Other	(6,619)	(2,723)
Net cash used for investing activities	(76,505)	(1,729)
Net change in cash and cash equivalents	(243,063)	4
Cash and cash equivalents at beginning of period	243,220	120
Cash and cash equivalents at end of period	$157	$124

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

Table of Contents

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In thousands)	2011	2010	2011	2010
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$248,320	$372,480	$795,578	$1,108,751
Gross receipts tax collections	13,212	17,414	42,468	51,100
Total revenues	261,532	389,894	838,046	1,159,851
OPERATING EXPENSES:				
Purchased power from affiliates	57,990	165,125	160,109	486,470
Purchased power from non-affiliates	65,407	92,648	271,302	270,900
Other operating expenses	39,007	58,832	124,905	198,296
Provision for depreciation	16,126	14,859	46,469	46,146
Amortization (deferral) of regulatory assets, net	19,164	(1,771)	44,779	(22,259)
General taxes	15,912	19,194	51,313	54,375
Total operating expenses	213,606	348,887	698,877	1,033,928
OPERATING INCOME	47,926	41,007	139,169	125,923
OTHER INCOME (EXPENSE):				
Miscellaneous income	797	1,508	1,466	4,431
Interest expense	(17,401)	(17,581)	(51,996)	(52,501)
Capitalized interest	101	193	164	516
Total other expense	(16,503)	(15,880)	(50,366)	(47,554)
INCOME BEFORE INCOME TAXES	31,423	25,127	88,803	78,369
INCOME TAXES	11,270	5,311	36,626	28,280
NET INCOME	20,153	19,816	52,177	50,089
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	1,817	1,830	5,292	12,207
Unrealized gain on derivative hedges	15	16	48	48
Other comprehensive income	1,832	1,846	5,340	12,255
Income taxes on other comprehensive income	645	484	1,878	4,251
Other comprehensive income, net of tax	1,187	1,362	3,462	8,004
COMPREHENSIVE INCOME	$21,340	$21,178	$55,639	$58,093

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

23

Table of Contents

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands, except share amounts)	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$5
Receivables-		
Customers, net of allowance for uncollectible accounts of $2,263 in 2011 and $3,369 in 2010	119,060	148,864
Affiliated companies	15,479	54,052
Other	13,467	11,314
Notes receivable from affiliated companies	—	14,404
Prepaid taxes	9,044	14,026
Other	3,302	1,592
	160,354	244,257
UTILITY PLANT:		
In service	2,567,953	2,532,629
Less — Accumulated provision for depreciation	954,104	935,259
	1,613,849	1,597,370
Construction work in progress	70,995	30,505
	1,684,844	1,627,875
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	162,946	152,928
Non-utility generation trusts	127,408	80,244
Other	283	297
	290,637	233,469
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	768,628
Regulatory assets	264,240	163,407
Power purchase contract asset	3,220	5,746
Other	15,212	19,287
	1,051,300	957,068
	$3,187,135	$3,062,669
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$45,000	$45,000
Short-term borrowings-		
Affiliated companies	112,901	101,338
Accounts payable-		
Affiliated companies	24,643	35,626
Other	27,831	41,420
Accrued taxes	3,526	5,075
Accrued interest	23,898	17,378
Other	24,699	22,541
	262,498	268,378
CAPITALIZATION:		
Common stockholder’s equity-		

Common stock, $20 par value, authorized 5,400,000 shares - 4,427,577 shares outstanding	88,552	88,552
Other paid-in capital	913,393	913,519
Accumulated other comprehensive loss	(160,064)	(163,526)
Retained earnings	43,170	60,993
Total common stockholder’s equity	885,051	899,538
Long-term debt and other long-term obligations	1,072,494	1,072,262
	1,957,545	1,971,800
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	431,811	371,877
Retirement benefits	189,311	187,621
Power purchase contract liability	188,432	116,972
Asset retirement obligations	103,139	98,132
Other	54,399	47,889
	967,092	822,491
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$3,187,135	$3,062,669

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

Table of Contents

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In thousands)	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$52,177	$50,089
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	46,469	46,146
Amortization (deferral) of regulatory assets, net	44,779	(22,259)
Deferred costs recoverable as regulatory assets	(64,872)	(61,574)
Deferred income taxes and investment tax credits, net	56,441	94,015
Accrued compensation and retirement benefits	8,272	7,634
Cash collateral paid, net	(1,439)	(11,760)
Decrease (increase) in operating assets-		
Receivables	70,493	(2,584)
Prepaid taxes	4,982	(29,318)
Increase (decrease) in operating liabilities-		
Accounts payable	(30,415)	(12,766)
Accrued taxes	(14,401)	(2,245)
Accrued interest	6,520	6,915
Other	21,654	9,411
Net cash provided from operating activities	200,660	71,704
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	25,000	—
Short-term borrowings, net	11,563	1,771
Redemptions and Repayments-		
Long-term debt	(25,000)	—
Common stock dividend payments	(70,000)	—
Other	(1,419)	(125)
Net cash provided from (used for) financing activities	(59,856)	1,646
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(93,685)	(91,924)
Loans to affiliated companies, net	14,404	—
Sales of investment securities held in trusts	413,584	141,392
Purchases of investment securities held in trusts	(464,940)	(116,240)
Other	(10,170)	(6,584)
Net cash used for investing activities	(140,807)	(73,356)
Net change in cash and cash equivalents	(3)	(6)
Cash and cash equivalents at beginning of period	5	14
Cash and cash equivalents at end of period	$2	$8

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

Table of Contents

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Table of Contents

COMBINED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy 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), ATSI, JCP&L, Met-Ed, Penelec, FENOC, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP and TrAIL), 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 (See Note 2). FirstEnergy and its subsidiaries follow GAAP and comply with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC and the NJBPU. These unaudited interim financial statements and notes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual 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.

These unaudited 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, 2010 for FirstEnergy, FES and the Utility Registrants, as applicable. The consolidated unaudited financial statements of FirstEnergy, FES and each of the Utility Registrants reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. Certain prior year amounts have been reclassified to conform to the current year presentation. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary (see Note 8). Investments in affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income.

2. MERGER

Merger

On February 25, 2011, the merger between FirstEnergy and AE closed. Pursuant to the terms of the Agreement and Plan of Merger among FirstEnergy, Merger Sub and AE, Merger Sub merged with and into AE, with AE continuing as the surviving corporation and becoming a wholly owned subsidiary of FirstEnergy. As part of the merger, AE shareholders received 0.667 of a share of FirstEnergy common stock for each share of AE common stock outstanding as of the date the merger was completed, and all outstanding AE equity-based employee compensation awards were converted into FirstEnergy equity-based awards on the same basis.

The total consideration in the merger was based on the closing price of a share of FirstEnergy common stock on February 24, 2011, the day prior to the date the merger was completed, and was calculated as follows (in millions, except per share data):

Shares of AE common stock outstanding on February 24, 2011	170
Exchange ratio	0.667
Number of shares of FirstEnergy common stock issued	113
Closing price of FirstEnergy common stock on February 24, 2011	$38.16

Fair value of shares issued by FirstEnergy	$4,327
Fair value of replacement share-based compensation awards relating to pre-merger service	27
Total consideration transferred	$4,354

The allocation of the total consideration transferred in the merger to the assets acquired and liabilities assumed includes adjustments for the fair value of Allegheny coal contracts, energy supply contracts, emission allowances, unregulated property, plant and equipment, derivative instruments, goodwill, intangible assets, long-term debt and accumulated deferred income taxes. The preliminary allocation of the purchase price is as follows:

27

Table of Contents

(In millions)	
Current assets	$1,493
Property, plant and equipment	9,656
Investments	138
Goodwill	873
Other noncurrent assets	1,352
Current liabilities	(718)
Noncurrent liabilities	(3,446)
Long-term debt and other long-term obligations	(4,994)
	$4,354

The allocation of purchase price in the table above reflects refinements made since the merger date in the determination of the fair values of income tax benefits, certain coal contracts and an adverse purchase power contract. This primarily resulted in an increase in other noncurrent assets of approximately $90 million and decreases in current assets, goodwill and noncurrent liabilities of $16 million, $79 million and $7 million, respectively. The impact of the refinements on the amortization of purchase accounting adjustments recorded during the quarters ended March 31, 2011, June 30, 2011 and September 30, 2011, were not significant. Further modifications to the purchase price allocation may occur as a result of continuing review of the assets acquired and liabilities assumed.

The estimated fair values of the assets acquired and liabilities assumed have been determined based on the accounting guidance for fair value measurements under GAAP, which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The Allegheny delivery, transmission and unregulated generation businesses have been assigned to the Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services segments, respectively. The preliminary estimate of goodwill from the merger of $873 million has been assigned to the Competitive Energy Services segment based on expected synergies from the merger. The goodwill is not deductible for tax purposes.

Total goodwill recognized by segment in FirstEnergy's Consolidated Balance Sheet is as follows:

(In millions)	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other/ Corporate	Consolidated
Balance as of December 31, 2010	$5,551	$24	$—	$—	$5,575
Merger with Allegheny	—	873	—	—	873
Balance as of September 30, 2011	$5,551	$897	$—	$—	$6,448

The preliminary valuation of the additional intangible assets and liabilities recorded as result of the merger is as follows:

Table of Contents

(In millions)	Preliminary Valuation	Weighted Average Amortization Period
Above market contracts:		
Energy contracts	$189	10 years
NUG contracts	124	25 years
Coal supply contracts	516	8 years
	829	
Below market contracts:		
NUG contracts	143	13 years
Coal supply contracts	83	7 years
Transportation contract	35	8 years
	261	
Net intangible assets	$568	

The fair value measurements of intangible assets and liabilities were based on significant unobservable inputs and thus represent level 3 measurements as defined in accounting guidance for fair value measurements.

The fair value of Allegheny's energy, NUG and gas transportation contracts, both above-market and below-market, were estimated based on the present value of the above/below market cash flows attributable to the contracts based on the contract type, discounted by a current market interest rate consistent with the overall credit quality of the contract portfolio. The above/below market cash flows were estimated by comparing the expected cash flow based on existing contracted prices and expected volumes with the cash flows from estimated current market contract prices for the same expected volumes. The estimated current market contract prices were derived considering current market prices, such as the price of energy and transmission, miscellaneous fees and a normal profit margin. The weighted average amortization period was determined based on the expected volumes to be delivered over the life of the contract.

The fair value of coal supply contracts was determined in a similar manner as the energy, NUG and gas transportation contracts based on the present value of the above/below market cash flows attributable to the contracts. The fair value adjustment for these contracts is being amortized based on expected deliveries under each contract.

As of September 30, 2011, intangible assets on FirstEnergy's Consolidated Balance Sheet, including those recorded in connection with the merger, include the following:

(In millions)	Intangible Assets
Purchase contract assets:	
NUG	$181
OVEC	53
	234
Other intangible assets:	
Coal contracts	465
FES customer intangible assets	126
Energy contracts	85
	676
Total intangible assets	$910

Acquired land easements and software with a fair value of $172 million are included in "Property, plant and equipment" on FirstEnergy's Consolidated Balance Sheet as of September 30, 2011.

In connection with the merger, FirstEnergy recorded merger transaction costs of approximately $2 million ($1 million net of tax) and $14 million ($11 million net of tax) during the three months ended September 30, 2011 and 2010, respectively, and approximately $91 million ($73 million net of tax) and $35 million ($26 million net of tax) during the first nine months of 2011 and 2010, respectively. These costs are included in “Other operating expenses” in the Consolidated Statements of Income. Merger transaction costs recognized in the first nine months of 2011 include $56 million ($47 million net of tax) of change in control and other benefit payments to AE executives.

Table of Contents

FirstEnergy also recorded approximately $3 million ($1 million net of tax) and $88 million ($67 million net of tax) in merger integration costs during the three and nine months ended September 30, 2011, respectively, including an inventory valuation adjustment. In connection with the merger, FirstEnergy reviewed its inventory levels as a result of combining the inventory of both companies. Following this review, FirstEnergy management determined that the combined inventory stock contained excess and duplicative items. FirstEnergy management also adopted a consistent excess and obsolete inventory practice for the combined entity. Application of the revised practice, in conjunction with those items identified as excess and duplicative, resulted in an inventory valuation adjustment of $67 million ($42 million net of tax) in the first quarter of 2011.

Revenues and earnings of Allegheny included in FirstEnergy's Consolidated Statement of Income for the periods subsequent to the February 25, 2011 merger date are as follows:

(In millions, except per share amounts)	July 1 - September 30, 2011	February 25 - September 30, 2011
Total revenues	$1,273	$2,891
Earnings Available to FirstEnergy Corp.(1)	$130	$147
Basic Earnings Per Share	$0.31	$0.37
Diluted Earnings Per Share	$0.31	$0.37

(1) Includes Allegheny's after-tax merger costs of $1 million and $57 million, respectively.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of FirstEnergy as if the merger with AE had taken place on January 1, 2010. The unaudited pro forma information has been calculated after applying FirstEnergy's accounting policies and adjusting Allegheny's results to reflect the depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, debt and intangible assets had been applied on January 1, 2010, together with the consequential tax effects. FirstEnergy and Allegheny both incurred non-recurring costs directly related to the merger that have been included in the pro forma earnings presented below. Combined pre-tax transaction costs incurred were approximately $1 million and $33 million in the three months ended September 30, 2011 and 2010, respectively, and approximately $91 million and $72 million in the nine months ended September 30, 2011 and 2010, respectively. In addition, during the nine months ended September 30, 2011, $88 million of pre-tax merger integration costs and $33 million of charges from merger settlements approved by regulatory agencies were recognized. Charges resulting from merger settlements are not expected to be material in future periods.

The unaudited pro forma financial information has been presented below for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger been completed on January 1, 2010, or the future consolidated results of operations of the combined company.

(Pro forma amounts in millions, except per share amounts)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Revenues	$4,708	$5,072	$13,556	$14,158
Earnings available to FirstEnergy	$512	$300	$835	$944
Basic Earnings Per Share	$1.22	$0.72	$2.00	$2.26
Diluted Earnings Per Share	$1.22	$0.71	$1.99	$2.25

3. GOODWILL

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 accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit's goodwill is less than the carrying value of its goodwill.

With the completion of the AE merger in the first quarter of 2011, FirstEnergy reorganized its management structure, which resulted in changes to its operating segments (see Note 14). FirstEnergy's goodwill from the merger of $873 million was assigned to the Competitive Energy Services segment based on expected synergies from the merger. FirstEnergy's reporting units are consistent

Table of Contents

with its operating segments, and consist of Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services. Goodwill is allocated to these operating segments based on the original purchase price allocation for acquisitions, including the AE merger, within the various reporting units. As of September 30, 2011, goodwill balances for Regulated Distribution and Competitive Energy Services were $5,551 million and $897 million, respectively. No goodwill has been allocated to the Regulated Independent Transmission segment.

Annual impairment testing is conducted during the third quarter of each year and for 2011, the analysis indicated no impairment of goodwill. For purposes of annual testing the estimated fair values of Regulated Distribution and Competitive Energy Services were determined using a discounted cash flow approach.

The discounted cash flow model of the Regulated Distribution and Competitive Energy Services segments reporting units is based on the forecasted operating cash flow for the current year, projected operating cash flows (determined using forecasted amounts as well as an estimated growth rate) and a terminal value. Discounted cash flows consist of the operating cash flows for each reporting unit less an estimate for capital expenditures. The key assumptions incorporated in the discounted cash flow approach include growth rates, projected operating income, changes in working capital, projected capital expenditures, planned funding of pension plans, anticipated funding of nuclear decommissioning trusts, expected results of future rate proceedings (applicable to Regulated Distribution segment only) and a discount rate equal to assumed long-term cost of capital. Cash flows may be adjusted to exclude certain non-recurring or unusual items. Reporting unit income, which excludes non-recurring or unusual items, was the starting point for determining operating cash flow and there were no non-recurring or unusual items excluded from the calculations of operating cash flow in any of the periods included in the determination of fair value.

This approach involves management judgment and estimates that are used in relation to changing market conditions and business environment; unanticipated changes in assumptions could have a significant effect on FirstEnergy's evaluation of goodwill. At the time FirstEnergy conducted the annual impairment testing in 2011, fair value would have to have declined in excess of 44% and 53% for Regulated Distribution and Competitive Energy Services, respectively, to indicate a potential goodwill impairment. Fair value would have to have declined more than 20% for CEI, 16% for TE, 38% for JCP&L, 62% for Met-Ed, 58% for Penelec and 62% for FES to indicate a potential goodwill impairment.

4. EARNINGS PER SHARE

Basic earnings per share of common stock are computed using the weighted average 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 would be issued 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	
	2011	2010	2011	2010
	(In millions, except per share amounts)			
Earnings Available to FirstEnergy Corp.	$511	$179	$742	$599
Weighted average number of basic shares outstanding[1]	418	304	392	304
Assumed exercise of dilutive stock options and awards[2]	2	1	2	1
Weighted average number of diluted shares outstanding[1]	420	305	394	305
Basic earnings per share of common stock	$1.22	$0.59	$1.89	$1.97
Diluted earnings per share of common stock	$1.22	$0.59	$1.88	$1.96

(1) Includes 113 million shares issued to AE shareholders for the periods subsequent to the merger date. (See Note 2)

(2) 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, 2011 and 2010.

5. FAIR VALUE MEASUREMENTS

(A) 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 on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption “short-term borrowings.” 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, 2011, and

Table of Contents

December 31, 2010:

	September 30, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy[1]	$17,870	$19,703	$13,928	$14,845
FES	3,738	3,975	4,279	4,403
OE	1,158	1,404	1,159	1,321
CEI	1,831	2,096	1,853	2,035
TE	600	720	600	653
JCP&L	1,787	2,074	1,810	1,962
Met-Ed	729	818	742	821
Penelec	1,120	1,245	1,120	1,189

(1) Includes debt assumed in the AE merger (see Note 2) with a carrying value and a fair value as of September 30, 2011, of $4,375 million and $4,515 million, respectively, and debt classified as liabilities related to assets pending sale (see Note 15) with a carrying value and a fair value as of September 30, 2011, of $363 million.

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those obligations 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 debt with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy, FES, the Utilities and other subsidiaries listed above.

(B) 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, available-for-sale securities and notes receivable.

FirstEnergy and its subsidiaries periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold an equity investment until recovery and then consider, among other factors, the duration and the extent to which the security’s fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy 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, OE and TE 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, Met-Ed and Penelec are subject to regulatory accounting. Net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in the trust and the decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the nuclear decommissioning trust 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 and the Utility Registrants hold debt and equity securities within their NDT, nuclear fuel disposal trusts and NUG trusts. These trust investments are considered as available-for-sale at fair market value. FES and the Utility Registrants have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in NDT, nuclear fuel disposal trusts and NUG trusts as of September 30, 2011 and December 31, 2010:

32

Table of Contents

	September 30, 2011[1]				December 31, 2010[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities								
FirstEnergy	$689	$11	$—	$700	$1,699	$31	$—	$1,730
FES	227	1	—	228	980	13	—	993
OE	—	—	—	—	123	1	—	124
TE	45	—	—	45	42	—	—	42
JCP&L	253	8	—	261	281	9	—	290
Met-Ed	41	—	—	41	127	4	—	131
Penelec	123	2	—	125	145	4	—	149
Equity securities								
FirstEnergy	$174	$6	$—	$180	$268	$69	$—	$337
FES	83	4	—	87	—	—	—	—
TE	23	1	—	24	—	—	—	—
JCP&L	19	—	—	19	80	17	—	97
Met-Ed	30	1	—	31	125	35	—	160
Penelec	19	—	—	19	63	16	—	79

(1) Excludes cash investments, receivables, payables, taxes and accrued income: FirstEnergy – $1,526 million; FES – $872 million; OE – $136 million; TE – $9 million; JCP&L – $133 million; Met-Ed – $229 million and Penelec – $147 million.

(2) Excludes cash investments, receivables, payables, taxes and accrued income: FirstEnergy – $193 million; FES – $153 million; OE – $3 million; TE – $34 million; JCP&L – $3 million; Met-Ed – $(3) million and Penelec – $4 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales net of adjustments recorded to earnings and interest and dividend income for the three months and nine months ended September 30, 2011 and 2010 were as follows:

Three Months Ended September 30

2011	Sales 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
TE	51	4	(2)	—
JCP&L	234	11	(4)	5
Met-Ed	306	15	(8)	3
Penelec	149	9	(4)	2

2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$662	$49	$(32)	$19
FES	521	47	(30)	11
OE	19	—	—	1
TE	12	—	(1)	—
JCP&L	59	1	(1)	4
Met-Ed	44	1	—	2
Penelec	7	—	—	1

33

Table of Contents

Nine Months Ended September 30

2011	Sales 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
TE	80	5	(4)	2
JCP&L	610	37	(10)	13
Met-Ed	807	63	(15)	8
Penelec	414	34	(11)	5

2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$2,577	$132	$(118)	$56
FES	1,478	101	(88)	33
OE	79	2	—	2
TE	118	3	(1)	1
JCP&L	340	10	(10)	10
Met-Ed	420	10	(12)	5
Penelec	141	6	(7)	5

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains and losses, and approximate fair values of investments in held-to-maturity securities as of September 30, 2011, and December 31, 2010:

	September 30, 2011				December 31, 2010			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt Securities								
FirstEnergy	$414	$45	$—	$459	$476	$91	$—	$567
OE	178	17	—	195	190	51	—	241
CEI	287	27	—	314	340	41	—	381

Investments in emission allowances, employee benefits and cost and equity method investments totaling $312 million as of September 30, 2011 and $259 million as of December 31, 2010, are not required to be disclosed and are excluded from the amounts reported above.

Notes Receivable

The table below provides the approximate fair value and related carrying amounts of notes receivable as of September 30, 2011, and December 31, 2010. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2013 to 2016.

Table of Contents

	September 30, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Notes Receivable				
FirstEnergy	$—	$—	$7	$8
TE	82	92	104	118

(C) RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements.

The three levels of the fair value hierarchy are as follows:

Level 1	— Quoted prices for identical instruments in active markets.
Level 2	— Quoted prices for similar instruments in active markets; — quoted prices for identical or similar instruments in markets that are not active; and — model-derived valuations for which all significant inputs are observable market data.
Level 3	— Valuation inputs are unobservable and significant to the fair value measurement.

The following tables set forth financial assets and liabilities measured at fair value on a recurring basis by level within the fair value hierarchy. There were no significant transfers between levels during the three months and nine months ended September 30, 2011.

FirstEnergy Corp.

The following tables summarize assets and liabilities recorded on FirstEnergy's Consolidated Balance Sheets at fair value as of September 30, 2011, and December 31, 2010:

Table of Contents

September 30, 2011	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$60	$—	$60
Derivative assets — commodity contracts	—	225	—	225
Derivative assets — FTRs	—	—	4	4
Derivative assets — NUG contracts(1)	—	—	59	59
Equity securities(2)	181	—	—	181
Foreign government debt securities	—	2	—	2
U.S. government debt securities	—	331	—	331
U.S. state debt securities	—	310	—	310
Other(4)	—	1,564	—	1,564
Total assets	$181	$2,492	$63	$2,736
Liabilities				
Derivative liabilities — commodity contracts	$—	$(257)	$—	$(257)
Derivative liabilities — FTRs	—	—	(13)	(13)
Derivative liabilities — NUG contracts(1)	—	—	(542)	(542)
Total liabilities	$—	$(257)	$(555)	$(812)
Net assets (liabilities)(3)	$181	$2,235	$(492)	$1,924

December 31, 2010	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$597	$—	$597
Derivative assets — commodity contracts	—	250	—	250
Derivative assets — NUG contracts(1)	—	—	122	122
Equity securities(2)	338	—	—	338
Foreign government debt securities	—	149	—	149
U.S. government debt securities	—	595	—	595
U.S. state debt securities	—	379	—	379
Other(4)	—	219	—	219
Total assets	$338	$2,189	$122	$2,649
Liabilities				
Derivative liabilities — commodity contracts	$—	$(348)	$—	$(348)
Derivative liabilities — NUG contracts(1)	—	—	(466)	(466)
Total liabilities	$—	$(348)	$(466)	$(814)
Net assets (liabilities)(3)	$338	$1,841	$(344)	$1,835

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

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(29) million and $(7) million as of September 30, 2011 and December 31, 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by the Utilities and FTRs held by FirstEnergy and classified as Level 3 in the fair value hierarchy during the periods ending September 30, 2011 and December 31, 2010:

36

Table of Contents

	Derivative Asset[(1)]	Derivative Liability[(1)]	Net[(1)]
	(In millions)		
January 1, 2011 Balance	$122	$(466)	$(344)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(52)	(285)	(337)
Purchases	13	(3)	10
Issuances	—	—	—
Sales	—	—	—
Settlements	(20)	211	191
Transfers into Level 3	—	(12)	(12)
September 30, 2011 Balance	$63	$(555)	$(492)
January 1, 2010 Balance	$200	$(643)	$(443)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(71)	(110)	(181)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(7)	287	280
Transfers into Level 3	—	—	—
December 31, 2010 Balance	$122	$(466)	$(344)

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

FirstEnergy Solutions Corp.

The following tables summarize assets and liabilities recorded on FES' Consolidated Balance Sheets at fair value as of September 30, 2011 and December 31, 2010:

Table of Contents

September 30, 2011	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$53	$—	$53
Derivative assets — commodity contracts	—	200	—	200
Derivative assets — FTRs	—	—	2	2
Equity securities[3]	87	—	—	87
Foreign government debt securities	—	2	—	2
U.S. government debt securities	—	172	—	172
Other[2]	—	904	—	904
Total assets	$87	$1,331	$2	$1,420
Liabilities				
Derivative liabilities — commodity contracts	$—	$(238)	$—	$(238)
Derivative liabilities — FTRs	—	—	(4)	(4)
Total liabilities	$—	$(238)	$(4)	$(242)
Net assets (liabilities)[1]	$87	$1,093	$(2)	$1,178

December 31, 2010	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$528	$—	$528
Derivative assets — commodity contracts	—	241	—	241
Foreign government debt securities	—	147	—	147
U.S. government debt securities	—	308	—	308
U.S. state debt securities	—	6	—	6
Other[2]	—	148	—	148
Total assets	$—	$1,378	$—	$1,378
Liabilities				
Derivative liabilities — commodity contracts	$—	$(348)	$—	$(348)
Total liabilities	$—	$(348)	$—	$(348)
Net assets[1]	$—	$1,030	$—	$1,030

(1) Excludes $(31) million and $7 million as of September 30, 2011 and December 31, 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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

(3) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

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 during the period ending September 30, 2011:

Table of Contents

	Derivative Asset FTRs (In millions)	Derivative Liability FTRs	Net FTRs
January 1, 2011 Balance	$—	$—	$—
Realized gain (loss)	—	—	—
Unrealized gain (loss)	4	(4)	—
Purchases	2	—	2
Issuances	—	—	—
Sales	—	—	—
Settlements	(4)	—	(4)
Transfers in (out) of Level 3	—	—	—
September 30, 2011 Balance	$2	$(4)	$(2)

Ohio Edison Company

The following tables summarize assets and liabilities recorded on OE's Consolidated Balance Sheets at fair value as of September 30, 2011 and December 31, 2010:

September 30, 2011	Level 1 (In millions)	Level 2	Level 3	Total
Assets				
Other[2]	$—	$138	$—	$138
Total assets[1]	$—	$138	$—	$138

December 31, 2010	Level 1 (In millions)	Level 2	Level 3	Total
Assets				
U.S. government debt securities	$—	$124	$—	$124
Other	—	2	—	2
Total assets[1]	$—	$126	$—	$126

(1) Excludes $(2) million and $1 million as of September 30, 2011 and December 31, 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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

The Toledo Edison Company

The following tables summarize assets and liabilities recorded on TE's Consolidated Balance Sheets at fair value as of September 30, 2011 and December 31, 2010:

Table of Contents

September 30, 2011	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$7	$—	$7
Equity securities[3]	24	—	—	24
U.S. government debt securities	—	38	—	38
Other[2]	—	9	—	9
Total assets[1]	$24	$54	$—	$78

December 31, 2010	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$7	$—	$7
U.S. government debt securities	—	33	—	33
U.S. state debt securities	—	1	—	1
Other[2]	—	35	—	35
Total assets[1]	$—	$76	$—	$76

(1) Excludes $2 million as of December 31, 2010 of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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

(3) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

Jersey Central Power & Light Company

The following tables summarize assets and liabilities recorded on JCP&L's Consolidated Balance Sheets at fair value as of September 30, 2011 and December 31, 2010:

Table of Contents

September 30, 2011	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Derivative assets — NUG contracts[1]	$—	$—	$4	$4
Equity securities[2]	20	—	—	20
U.S. government debt securities	—	51	—	51
U.S. state debt securities	—	212	—	212
Other[4]	—	123	—	123
Total assets	$20	$386	$4	$410
Liabilities				
Derivative liabilities — NUG contracts[1]	$—	$—	$(222)	$(222)
Total liabilities	$—	$—	$(222)	$(222)
Net assets (liabilities)[3]	$20	$386	$(218)	$188

December 31, 2010	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$23	$—	$23
Derivative assets — commodity contracts	—	2	—	2
Derivative assets — NUG contracts[1]	—	—	6	6
Equity securities[2]	96	—	—	96
U.S. government debt securities	—	33	—	33
U.S. state debt securities	—	236	—	236
Other[4]	—	4	—	4
Total assets	$96	$298	$6	$400
Liabilities				
Derivative liabilities — NUG contracts[1]	$—	$—	$(233)	$(233)
Total liabilities	$—	$—	$(233)	$(233)
Net assets (liabilities)[3]	$96	$298	$(227)	$167

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

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $6 million and $(3) million as of September 30, 2011 and December 31, 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by JCP&L and classified as Level 3 in the fair value hierarchy during the periods ending September 30, 2011 and December 31, 2010:

Table of Contents

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
	(In millions)		
January 1, 2011 Balance	$6	$(233)	$(227)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(2)	(71)	(73)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	—	82	82
Transfers in (out) of Level 3	—	—	—
September 30, 2011 Balance	$4	$(222)	$(218)
January 1, 2010 Balance	$8	$(399)	$(391)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(1)	36	35
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(1)	130	129
Transfers in (out) of Level 3	—	—	—
December 31, 2010 Balance	$6	$(233)	$(227)

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

Metropolitan Edison Company

The following tables summarize assets and liabilities recorded on Met-Ed’s Consolidated Balance Sheets at fair value as of September 30, 2011 and December 31, 2010:

Table of Contents

September 30, 2011	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$—	$—	$—
Derivative assets — NUG contracts[1]	—	—	52	52
Equity securities[2]	31	—	—	31
Foreign government debt securities	—	—	—	—
U.S. government debt securities	—	41	—	41
U.S. state debt securities	—	—	—	—
Other[4]	—	233	—	233
Total assets	$31	$274	$52	$357
Liabilities				
Derivative liabilities — NUG contracts[1]	$—	$—	$(132)	$(132)
Total liabilities	$—	$—	$(132)	$(132)
Net assets (liabilities)[3]	$31	$274	$(80)	$225

December 31, 2010	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$32	$—	$32
Derivative assets — commodity contracts	—	5	—	5
Derivative assets — NUG contracts[1]	—	—	112	112
Equity securities[2]	160	—	—	160
Foreign government debt securities	—	1	—	1
U.S. government debt securities	—	88	—	88
U.S. state debt securities	—	2	—	2
Other[4]	—	14	—	14
Total assets	$160	$142	$112	$414
Liabilities				
Derivative liabilities — NUG contracts[1]	$—	$—	$(116)	$(116)
Total liabilities	$—	$—	$(116)	$(116)
Net assets (liabilities)[3]	$160	$142	$(4)	$298

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

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $(3) million and $(9) million as of September 30, 2011 and December 31, 2010, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

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

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by Met-Ed and classified as Level 3 in the fair value hierarchy during the periods ending September 30, 2011 and December 31, 2010:

Table of Contents

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
	(In millions)		
January 1, 2011 Balance	$112	$(116)	$(4)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(54)	(61)	(115)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(6)	45	39
Transfers in (out) of Level 3	—	—	—
September 30, 2011 Balance	$52	$(132)	$(80)
January 1, 2010 Balance	$176	$(143)	$33
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(59)	(38)	(97)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(5)	65	60
Transfers in (out) of Level 3	—	—	—
December 31, 2010 Balance	$112	$(116)	$(4)

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

Pennsylvania Electric Company

The following tables summarize assets and liabilities recorded on Penelec’s Consolidated Balance Sheets at fair value as of September 30, 2011 and December 31, 2010:

Table of Contents

September 30, 2011	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Derivative assets — NUG contracts[1]	$—	$—	$3	$3
Equity securities[2]	19	—	—	19
U.S. government debt securities	—	28	—	28
U.S. state debt securities	—	98	—	98
Other[4]	—	144	—	144
Total assets	$19	$270	$3	$292
Liabilities				
Derivative liabilities — NUG contracts[1]	$—	$—	$(188)	$(188)
Total liabilities	$—	$—	$(188)	$(188)
Net assets (liabilities)[3]	$19	$270	$(185)	$104

December 31, 2010	Level 1	Level 2	Level 3	Total
	(In millions)			
Assets				
Corporate debt securities	$—	$8	$—	$8
Derivative assets — commodity contracts	—	2	—	2
Derivative assets — NUG contracts[1]	—	—	4	4
Equity securities[2]	81	—	—	81
U.S. government debt securities	—	9	—	9
U.S. state debt securities	—	133	—	133
Other[4]	—	5	—	5
Total assets	$81	$157	$4	$242
Liabilities				
Derivative liabilities — NUG contracts[1]	$—	$—	$(117)	$(117)
Total liabilities	$—	$—	$(117)	$(117)
Net assets (liabilities)[3]	$81	$157	$(113)	$125

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

(2) NDT funds hold equity portfolios the performance of which is benchmarked against the S&P 500 Index or Russell 3000 Index.

(3) Excludes $1 million and $(3) million as of September 30, 2011 and December 31, 2010, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

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

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and commodity contracts held by Penelec and classified as Level 3 in the fair value hierarchy during the periods ended September 30, 2011 and December 31, 2010:

Table of Contents

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
	(In millions)		
January 1, 2011 Balance	$4	$(117)	$(113)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	—	(139)	(139)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(1)	68	67
Transfers in (out) of Level 3	—	—	—
September 30, 2011 Balance	$3	$(188)	$(185)
January 1, 2010 Balance	$16	$(101)	$(85)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	(11)	(108)	(119)
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	(1)	92	91
Transfers in (out) of Level 3	—	—	—
December 31, 2010 Balance	$4	$(117)	$(113)

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

During the three months ended September 30, 2011, FirstEnergy received approximately $130 million from assigning a substantially below-market, long-term fossil fuel contract to a third party. As a result, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices. The new contract runs for nine years, which is the remaining term of the assigned contract. The transaction reduced fuel costs during the quarter by approximately $123 million.

6. 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. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties.

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 AOCL. 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 December 2018.

Cash Flow Hedges

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

As of December 31, 2010, commodity derivative contracts designated in cash flow hedging relationships were $104 million of assets and $101 million of liabilities. In February 2011, FirstEnergy elected to dedesignate all outstanding cash flow hedge relationships. Total net unamortized gains included in AOCL associated with dedesignated cash flow hedges totaled $12 million as of September 30, 2011. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Reclassifications from AOCL into other operating expenses were less than $1 million and $19 million during the three months and nine months ended September 30, 2011, respectively. Approximately $1 million is expected to be amortized to expense during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with

Table of Contents

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, 2011, no forward starting swap agreements were outstanding. Total unamortized losses included in AOCL associated with prior interest rate cash flow hedges totaled $81 million as of September 30, 2011. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months. Reclassifications from AOCL into interest expense totaled $3 million during the three months ended September 30, 2011, and 2010 and $9 million during the nine months ended September 30, 2011 and 2010.

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, 2011, 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 $107 million as of September 30, 2011. Based on current estimates, approximately $21 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $5 million during the three months ended September 30, 2011 and 2010, respectively, and $16 million and $7 million during the nine months ended September 30, 2011 and 2010, respectively.

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 natural gas is used 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. Interest rate swaps include two interest rate swap agreements that expired during 2011 with an aggregate notional value of $200 million that were entered into during 2003 to substantially offset two existing interest rate swaps with the same counterparty. The 2003 agreements effectively locked in a net liability and substantially eliminated future income volatility from the interest rate swap positions but do not qualify for cash flow hedge accounting. Derivative instruments are not used in quantities greater than forecasted needs.

As of September 30, 2011, FirstEnergy's net liability position under commodity derivative contracts was $41 million, which primarily related to FES positions. Under these commodity derivative contracts, FES posted $49 million and AE Supply posted $1 million in collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $48 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, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $14 million during the next twelve months.

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 in FirstEnergy's Consolidated Balance Sheets:

Table of Contents

Derivatives not designated as hedging instruments:

Derivative Assets	Fair Value September 30, 2011 (In millions)	December 31, 2010	Derivative Liabilities	Fair Value September 30, 2011 (In millions)	December 31, 2010
Power Contracts			Power Contracts		
Current Assets	$157	$96	Current Liabilities	$190	$209
Noncurrent Assets	68	40	Noncurrent Liabilities	67	38
FTRs			FTRs		
Current Assets	4	—	Current Liabilities	13	—
Noncurrent Assets	—	—	Noncurrent Liabilities	—	—
NUGs	59	122	NUGs	542	467
Interest Rate Swaps			Interest Rate Swaps		
Current Assets	—	—	Current Liabilities	—	—
Noncurrent Assets	—	—	Noncurrent Liabilities	—	—
Other			Other		
Current Assets	—	10	Current Liabilities	—	—
Noncurrent Assets	—	—	Noncurrent Liabilities	—	—
Total Derivatives Assets	$288	$268	Total Derivatives Liabilities	$812	$714

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of September 30, 2011:

	Purchases (In thousands)	Sales	Net	Units
Power Contracts	34,956	49,696	(14,740)	MWH
FTRs	45,730	27	45,703	MWH
NUGs	25,442	—	25,442	MWH

The effect of derivative instruments on the Consolidated Statements of Income during the three months and nine months ended September 30, 2011 and 2010, are summarized in the following tables:

Table of Contents

	Three Months Ended September 30				
	Power Contracts (In millions)	FTRs	Interest Rate Swaps	Other	Total
Derivatives in a Hedging Relationship					
2011					
Gain (Loss) Recognized in AOCL (Effective Portion)	$—	$—	$—	$—	$—
Effective Gain (Loss) Reclassified to: [1]					
Purchased Power Expense	—	—	—	—	—
Revenues	—	—	—	—	—
2010					
Gain (Loss) Recognized in AOCL (Effective Portion)	$(1)	$—	$—	$3	$2
Effective Gain (Loss) Reclassified to: [1]					
Purchased Power Expense	5	—	—	—	5
Revenues	(7)	—	—	—	(7)
Fuel Expense	—	—	—	(4)	(4)
Derivatives Not in a Hedging Relationship					
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$27	$—	$—	$—	$27
Revenues	3	—	—	—	3
Other Operating Expense	(11)	(15)	1	—	(25)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	(5)	—	—	—	(5)
Revenues	(40)	30	—	—	(10)
Other Operating Expense	—	(35)	—	—	(35)
2010					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$3	$—	$—	$—	$3
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	(22)	—	—	—	(22)

Derivatives Not in a Hedging Relationship with Regulatory Offset[2]	Three Months Ended September 30		
	NUGs (In millions)	Other	Total
2011			
Unrealized Gain (Loss) to Derivative Instrument:	$(89)	$(3)	$(92)
Unrealized Gain (Loss) to Regulatory Assets:	89	3	92
Realized Gain (Loss) to Derivative Instrument:	53	(3)	50
Realized Gain (Loss) to Regulatory Assets:	(53)	3	(50)

2010			
Unrealized Gain (Loss) to Derivative Instrument:	$(146)	—	$(146)
Unrealized Gain (Loss) to Regulatory Assets:	146	—	146
Realized Gain (Loss) to Derivative Instrument:	63	—	63
Realized Gain (Loss) to Regulatory Assets:	(63)	—	(63)

49

	Nine Months Ended September 30				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
	(In millions)				
Derivatives in a Hedging Relationship					
2011					
Gain (Loss) Recognized in AOCL (Effective Portion)	$5	$—	$—	$—	$5
Effective Gain (Loss) Reclassified to: (1)					
Purchased Power Expense	16	—	—	—	16
Revenues	(12)	—	—	—	(12)
2010					
Gain (Loss) Recognized in AOCL (Effective Portion)	$(3)	$—	$—	$10	$7
Effective Gain (Loss) Reclassified to:(1)					
Purchased Power Expense	(2)	—	—	—	(2)
Revenues	(11)	—	—	—	(11)
Fuel Expense	—	—	—	(11)	(11)
Derivatives Not in a Hedging Relationship					
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$88	$—	$—	$—	$88
Revenues	(1)	—	—	—	(1)
Other Operating Expense	(65)	(1)	2	—	(64)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	(41)	—	—	—	(41)
Revenues	(69)	56	—	—	(13)
Other Operating Expense	—	(122)	—	—	(122)
2010					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$42	$—	$—	$—	$42
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	(71)	—	—	—	(71)

Derivatives Not in a Hedging Relationship with Regulatory Offset(2)	Nine Months Ended September 30,		
	NUGs	Other	Total
	(In millions)		
2011			
Unrealized Gain (Loss) to Derivative Instrument:	$(325)	$—	$(325)
Unrealized Gain (Loss) to Regulatory Assets:	325	—	325
Realized Gain (Loss) to Derivative Instrument:	187	(14)	173
Realized Gain (Loss) to Regulatory Assets:	(187)	14	(173)
2010			

Unrealized Gain (Loss) to Derivative Instrument:	$(405)	—	$(405)
Unrealized Gain (Loss) to Regulatory Assets:	405	—	405
Realized Gain (Loss) to Derivative Instrument:	209	(9)	200
Realized Gain (Loss) to Regulatory Assets:	(209)	9	(200)

(1) The ineffective portion was immaterial.

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

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, 2011 and 2010:

Table of Contents

Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Three Months Ended September 30		
	NUGs	Other	Total
	(In millions)		
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)
Outstanding net asset (liability) as of July 1, 2010	$(557)	$10	$(547)
Additions/Change in value of existing contracts	(146)	—	(146)
Settled contracts	63	—	63
Outstanding net asset (liability) as of September 30, 2010	$(640)	$10	$(630)

Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Nine Months Ended September 30		
	NUGs	Other	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2011	$(345)	$10	$(335)
Additions/Change in value of existing contracts	(325)	—	(325)
Settled contracts	187	(14)	173
Outstanding net asset (liability) as of September 30, 2011	$(483)	$(4)	$(487)
Outstanding net asset (liability) as of January 1, 2010	$(444)	$19	$(425)
Additions/Change in value of existing contracts	(405)	—	(405)
Settled contracts	209	(9)	200
Outstanding net asset (liability) as of September 30, 2010	$(640)	$10	$(630)

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

7. PENSION AND OTHER POSTRETIREMENT 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.

FirstEnergy provides a portion of non-contributory pre-retirement basic life insurance for employees who are eligible to retire. 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 also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the three and nine months ended September 30, 2011, FirstEnergy made pre-tax contributions to its qualified pension plans of $112 million and $375 million, respectively.

As a result of the merger with AE, FirstEnergy assumed certain pension and OPEB plans. FirstEnergy measured the funded status of the Allegheny pension plans and other postretirement benefit plans as of the merger closing date using discount rates of 5.50% and 5.25%, respectively. The fair values of plan assets for Allegheny's pension plans and other postretirement benefit plans at the date of the merger were $954 million and $75 million, respectively, and the actuarially determined benefit obligations for such plans as of that date were $1,341 million and $272 million, respectively. The expected returns on plan assets used to calculate net periodic costs for periods in 2011 subsequent to the date of the merger are 8.25% for Allegheny's qualified pension plan and 5.00% for Allegheny's other postretirement benefit plans.

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

Table of Contents

Pension Benefit Cost (Credit)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
	(In millions)			
Service cost	$34	$25	$97	$74
Interest cost	96	79	277	236
Expected return on plan assets	(115)	(90)	(332)	(271)
Amortization of prior service cost	4	3	12	10
Recognized net actuarial loss	49	47	146	141
Curtailments[1]	—	—	(2)	—
Special termination benefits[1]	—	—	9	—
Net periodic cost	$68	$64	$207	$190

(1) Represents costs (credits) incurred related to change in control provision payments to certain executives who were terminated or were expected to be terminated as a result of the merger.

Other Postretirement Benefit Cost (Credit)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
	(In millions)			
Service cost	$4	$2	$10	$7
Interest cost	13	11	36	33
Expected return on plan assets	(10)	(9)	(30)	(27)
Amortization of prior service cost	(51)	(48)	(151)	(144)
Recognized net actuarial loss	14	15	42	45
Net periodic cost (credit)	$(30)	$(29)	$(93)	$(86)

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

Pension Benefit Cost	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
	(In millions)			
FES	$22	$22	$66	$66
OE	6	6	16	17
CEI	5	5	15	16
TE	1	2	4	5
JCP&L	5	6	15	19
Met-Ed	3	3	9	8
Penelec	4	5	13	14
Other FirstEnergy Subsidiaries	22	15	69	45
	$68	$64	$207	$190

Table of Contents

Other Postretirement Benefit Credit	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
	(In millions)			
FES	$(8)	$(7)	$(22)	$(20)
OE	(6)	(6)	(17)	(19)
CEI	(1)	(1)	(5)	(4)
TE	(1)	—	(1)	(1)
JCP&L	(1)	(2)	(5)	(5)
Met-Ed	(2)	(2)	(7)	(6)
Penelec	(2)	(2)	(7)	(6)
Other FirstEnergy Subsidiaries	(9)	(9)	(29)	(25)
	$(30)	$(29)	$(93)	$(86)

8. VARIABLE INTEREST ENTITIES

FirstEnergy and its subsidiaries perform qualitative analyses to determine whether a variable interest gives FirstEnergy or its subsidiaries 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.

VIEs included in FirstEnergy’s consolidated financial statements are: FEV’s joint venture in the Signal Peak mining and coal transportation operations, a portion of which was sold on October 18, 2011 (see Note 15); the PNBV and Shippingport bond trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; and 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 $287 million was outstanding as of September 30, 2011.

FirstEnergy and its subsidiaries reflect the portion of VIEs not owned by them in the caption noncontrolling interest within the consolidated financial statements. The change in noncontrolling interest within the Consolidated Balance Sheets during the nine months ended September 30, 2011, is primarily due to equity contributions from owners of $22 million, partially offset by net losses of the noncontrolling interests of $17 million and an equity distribution to owners of $5 million.

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.

PATH-WV

PATH, LLC 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, LLC 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 and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH Project to be constructed by PATH-WV.

Because of the nature of PATH-WV’s operations and its FERC approved rate mechanism, FirstEnergy’s maximum exposure to loss, through AE, consists of its equity investment in PATH-WV, which was $28 million as of September 30, 2011.

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 Utilities if the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed, Penelec, PE, WP and MP, maintains 23 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but four 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 four entities; however, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to

Table of Contents

evaluate entities.
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 four contracts that may contain a variable interest that were held by FirstEnergy subsidiaries during the three months ended September 30, 2011, were $44 million, $31 million and $14 million for JCP&L, PE and WP, respectively and $164 million, $89 million and $40 million for the nine months ended September 30, 2011, respectively. Purchased power costs related to the two contracts that may contain a variable interest that were held by JCP&L during the three and nine months ended September 30, 2010 were $73 million and $190 million, 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 that WP may hold a variable interest, for which WP has taken the scope exception. As of September 30, 2011, WP's reserve for this adverse purchase power commitment was $56 million, including a current liability of $11 million, and is being amortized over the life of the commitment.
Loss Contingencies
FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangement. FES and the Ohio Companies are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions mentioned above as of September 30, 2011:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
	(In millions)		
FES	$1,370	$1,176	$194
OE	613	455	158
CEI[2]	591	70	521
TE[2]	591	309	282

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.6 billion.
[2] CEI and TE are jointly and severally liable for the maximum loss amounts under certain sale-leaseback agreements.

9. INCOME TAXES

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As a result of the merger with AE, FirstEnergy's unrecognized income tax benefits increased by $97 million. During 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. There were no other material changes to FirstEnergy's unrecognized income tax benefits during the first nine months of 2011. After reaching settlements in 2010 on a state tax matter and tax items at appeals with the IRS related to the capitalization of certain costs for tax years 2005-2008 and on gains and losses recognized from the disposition of assets, FirstEnergy recognized approximately $78 million of net income tax benefits, including $21 million that favorably affected FirstEnergy's effective tax rate for 2010. The remaining portion of the income tax benefit recognized in 2010 increased FirstEnergy's accumulated deferred income taxes for the settled temporary tax item.
As of September 30, 2011, it is reasonably possible that approximately $46 million of unrecognized income tax benefits may be resolved within the next twelve months, of which approximately $4 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. The interest associated with the settlement of the claim noted above favorably affected FirstEnergy's effective tax rate by $6 million in 2011. There were no other material changes to the amount of accrued interest, except for a $6 million increase in accrued interest as a result of the merger with AE. The reversal of accrued interest associated with the recognized income tax benefits noted above favorably affected FirstEnergy's effective tax rate by $11 million in the first nine months of 2010. The net amount of interest accrued as of September 30, 2011 was $11 million, compared with $3 million as of December 31, 2010.

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.
The IRS issued guidance in the third quarter of 2011 providing a safe harbor method of tax accounting for electric transmission and distribution property to determine the tax treatment of repair costs for electric transmission and distribution assets. FirstEnergy is evaluating the method change for this temporary tax item and, if elected, is not expected to be material to the financial position or effective tax rates of FirstEnergy and the Utilities.
As a result of the Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act signed into law in March 2010, beginning in 2013 the tax deduction available to FirstEnergy will be reduced to the extent that drug costs are reimbursed under the Medicare Part D retiree subsidy program. As retiree healthcare liabilities and related tax impacts under prior law were already reflected in FirstEnergy’s consolidated financial statements, the change resulted in a charge to FirstEnergy’s earnings in the first quarter of 2010 of approximately $13 million and a reduction in accumulated deferred tax assets associated with these subsidies. That charge reflected the anticipated increase in income taxes that will occur as a result of the change in tax law.
Allegheny is currently under audit by the IRS for tax years 2007 and 2008. Allegheny has filed its 2010 and 2009 federal returns and such filings are subject to review. State tax returns for tax years 2008 through 2010 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE. FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2010) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2008-2010, as well as 2005-2007 for New Jersey. The IRS began auditing the year 2008 in February 2008 and the audit was completed in July 2010 with one item under appeal. Tax years 2009-2011 are under review by the IRS. 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.

10. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. As of September 30, 2011, outstanding guarantees and other assurances aggregated approximately $3.8 billion, consisting of parental guarantees ($0.9 billion), subsidiaries' guarantees ($2.5 billion), and surety bonds and LOCs ($0.4 billion).

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. FirstEnergy believes the likelihood is remote that such parental guarantees of $0.3 billion (included in the $0.9 billion discussed above) as of September 30, 2011 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or “material adverse event,” the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of September 30, 2011, FirstEnergy's maximum exposure under these collateral provisions was $594 million, consisting of $495 million due to a below investment grade credit rating (of which $257 million is due to an acceleration of payment or funding obligation) and $99 million due to “material adverse event” contractual clauses. Additionally, stress case conditions of a credit rating downgrade or “material adverse event” and hypothetical adverse price movements in the underlying commodity markets would increase this amount to $662 million.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $147 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, contracts entered into by the Competitive Energy Services segment, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions that require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' and AE Supply's power portfolios as of September 30, 2011, and forward prices as of that date, FES and AE Supply have posted collateral of $123 million and $1 million, respectively. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one-year time horizon), FES and AE Supply would be required to post an additional $16 million and $1 million of collateral, respectively. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required to be posted.

FES' debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, and FES guarantees the debt obligations of

Table of Contents

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.

Signal Peak and Global Rail are borrowers under a $350 million syndicated two-year senior secured term loan facility due in October 2012. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership in the borrowers with FEV, have provided a guaranty of the borrowers' obligations under the facility. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the lenders under the term loan facility as collateral for the facility. On October 18, 2011, FEV sold a portion of its ownership interest in Signal Peak and Global Rail (see Note 15). Following the sale, FirstEnergy, WMB Loan Ventures LLC and WMB Loan Ventures II LLC will continue to guarantee the borrowers' obligations until either the facility is replaced with non-recourse financing no earlier than January 1, 2012, and no later than June 30, 2012, or replaced with appropriate recourse financing no earlier than September 4, 2012, that provides for separate guarantees from each owner in proportion with each equity owner's percentage ownership in the joint venture.

(B) 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-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

In July 2008, three complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania seeking damages based on coal-fired Bruce Mansfield Plant air emissions. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner,” one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint seeking certification as a class action with the eight named plaintiffs as the class representatives. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the 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 Met-Ed in 1999) and Met-Ed. 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. In September 2009, the Court granted Met-Ed's motion to dismiss New Jersey's and Connecticut's claims for injunctive relief against Met-Ed, but denied Met-Ed's motion to dismiss the claims for civil penalties. The parties dispute the scope of Met-Ed's indemnity obligation to and from Sithe Energy, and Met-Ed 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 Portland coal-fired plant based on “modifications” dating back to 1986. On March 31, 2011, the EPA proposed emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Plant based on an interstate pollution transport petition submitted by New Jersey under Section 126 of the CAA. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on “modifications” dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of Keystone, and Penelec, as former owner and operator of Shawville, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. (Mission) alleging that "modifications" at the coal-fired Homer City Plant occurred from 1988 to the present without preconstruction NSR permitting in violation of the CAA's PSD program. In May 2010, the EPA issued a second NOV to Mission, Penelec, NYSEG and others that have had an ownership interest in Homer City containing in all material respects allegations identical to those included in the June 2008 NOV. In January 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against Penelec based on alleged "modifications" at Homer City 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 January 2011, another complaint was filed against Penelec and the other entities described above in the U.S. District Court for the Western District of Pennsylvania seeking damages based on Homer City's air emissions as well as certification as a class action and to enjoin Homer City from operating except in a "safe, responsible, prudent and proper manner." Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint, but, at this time, is unable to predict the outcome of this matter or estimate the loss or possible range of loss. In addition, the Commonwealth of Pennsylvania and the States of New Jersey and New York intervened and have filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. Mission is seeking indemnification from Penelec, the co-owner and operator of Homer City prior to its sale in 1999. On April 21, 2011, Penelec and all other defendants filed Motions to Dismiss all of the federal claims

Table of Contents

and the various state claims. Responsive and Reply briefs were filed on May 26, 2011 and June 17, 2011, respectively. On October 12 and 13, 2011, the Court dismissed all of the claims with prejudice, of the U.S. and the Commonwealth of Pennsylvania and the Sates of New Jersey and New York and all of the claims of the private parties, without prejudice to refile state law claims in state court, against all of the defendants, including Penelec.

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 occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake Plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake Plant. 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. Also, in June 2011, FirstEnergy received an information request pursuant to section 114(a) of the CAA for certain operating, maintenance and planning information, among other information regarding these plants. FGCO intends to comply with the CAA, including the EPA's information requests 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 CAA and related requirements, including potential application of the NSR standards 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. AE has provided responsive information to this and a subsequent request but is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In May 2004, AE, AE Supply, MP and WP received a Notice of Intent to Sue Pursuant to CAA §7604 from the Attorneys General of New York, New Jersey and Connecticut and from the PA DEP, alleging that Allegheny performed major modifications in violation of the PSD provisions of the CAA at the following West Virginia coal-fired plants: Albright Unit 3; Fort Martin Units 1 and 2; Harrison Units 1, 2 and 3; Pleasants Units 1 and 2 and Willow Island Unit 2. The Notice also alleged PSD violations at the Armstrong, Hatfield's Ferry and Mitchell coal-fired plants in Pennsylvania and identifies PA DEP as the lead agency regarding those facilities. In September 2004, AE, AE Supply, MP and WP received a separate Notice of Intent to Sue from the Maryland Attorney General that essentially mirrored the previous Notice.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the United States District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the CAA and the Pennsylvania Air Pollution Control Act at the Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. A non-jury trial on liability only was held in September 2010. Plaintiffs filed their proposed findings of fact and conclusions of law in December 2010, Allegheny made its related filings in February 2011 and plaintiffs filed their responses in April 2011. The parties are awaiting a decision from the District Court, but there is no deadline for that decision and we are unable to predict the outcome or estimate the possible loss or range of loss.

In September 2007, Allegheny also 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 Hatfield's Ferry and Armstrong Plants in Pennsylvania and the Fort Martin and Willow Island coal-fired plants in West Virginia. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NOx, requires mercury emission reductions and mandates that Maryland join the RGGI and participate in that coalition's regional efforts to reduce CO_2 emissions. On April 20, 2007, Maryland became the 10th state to join the RGGI. The Healthy Air Act provides a conditional exemption for the R. Paul Smith coal-fired plant for NOx, SO_2 and mercury, based on a PJM declaration that the plant is vital to reliability in the Baltimore/Washington DC metropolitan area, which PJM determined in 2006. Pursuant to the legislation, the MDE passed alternate NOx and SO_2 limits for R. Paul Smith, which became effective in April 2009. However, R. Paul Smith is still required to meet the Healthy Air Act mercury reductions of 80% which began in 2010. The statutory exemption does not extend to R. Paul Smith's CO_2 emissions. Maryland issued final regulations to implement RGGI requirements in February 2008. Ten RGGI auctions have been held through the end of calendar year 2010. RGGI allowances are also readily available in the allowance markets, affording another mechanism by which to secure necessary allowances. On March 14, 2011, MDE requested PJM perform an analysis to determine if termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region under current system conditions. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

Table of Contents

In January 2010, the WVDEP issued a NOV for opacity emissions at Allegheny's Pleasants coal-fired plant. In August 2011, Allegheny and WVDEP resolved the NOV through a Consent Order requiring installation of a reagent injection system to reduce opacity by September 2012.

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 Circuit vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." In December 2008, the Court reconsidered its prior ruling and 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 opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the "NOx SIP Call," cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the "8-hour" ozone NAAQS. In July 2011, the EPA finalized the CSAPR to replace CAIR, which remains in effect until CSAPR becomes effective (60 days after publication in the Federal Register). CSAPR requires 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 October 6, 2011, EPA proposed to revise the certain state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas) and generating unit allocations (for Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and proposed to delay restrictions on interstate trading of NOx and SO_2 emission allowances from 2012 to 2014. EPA's final CSAPR rule has been appealed to the U.S. Court of Appeals for the District of Columbia Circuit by various stakeholders, with several appellants seeking a stay of CSAPR pending its review by the Court. 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.

During the three months ended September 30, 2011, FirstEnergy recorded a pre-tax impairment charge of approximately $6 million ($1 million for FES and $5 million for AE Supply) for obsolete NOx emission allowances, including fair value adjustments in connection with the merger for AE Supply that can no longer be used after 2011. While the carrying value of FirstEnergy's SO_2 emission allowances are currently above market (currently reflected at $26 million on the Consolidated Balance Sheet as of September 30, 2011), Management determined that no impairment exists in the third quarter of 2011 since these allowances can be carried forward into future years. Management is continuing to assess the impact of CSAPR, other environmental proposals and other factors on FirstEnergy's competitive fossil generating facilities, including but not limited to, the impact on its SO_2 emission allowances and the continuing operations of its coal-fired plants.

Hazardous Air Pollutant Emissions

On March 16, 2011, the EPA released its MACT proposal to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. Final regulations are expected on or about December 16, 2011. Depending on the action taken by the EPA and how any future regulations are ultimately implemented, FirstEnergy's future cost of compliance with MACT regulations may be substantial and changes to FirstEnergy's operations may result.

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. The Senate continues to consider a number of measures to regulate GHG emissions. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, proposals to ensure that 10% of electricity used in the United States comes from renewable sources by 2012, to increase to 25% by 2025, to implement an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. 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 GHG emissions commencing in 2010 and currently requires it to submit reports. 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 permits under the CAA's NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO_2) effective January 2, 2011 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

Table of Contents

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 the next three years with a goal of increasing to $100 billion by 2020; and establishes the “Copenhagen 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.

In 2009, the U.S. Court of Appeals for the Second Circuit and the U.S. Court of Appeals for the Fifth Circuit reversed and remanded lower court decisions that had dismissed complaints alleging damage from GHG emissions on jurisdictional grounds. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. These cases involve common law tort claims, including public and private nuisance, alleging that GHG emissions contribute to global warming and result in property damages. The U.S. Supreme Court granted a writ of certiorari to review the decision of the Second Circuit. On June 20, 2011, the U.S. Supreme Court reversed the Second Circuit. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions. The Court's ruling also failed to answer the question of the extent to which actions for damages may remain viable.

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 Clean Water Act 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 Clean Water Act 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 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 Clean Water Act 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 Clean Water Act generally requiring fish impingement to be reduced to a 12% annual average and studies to be conducted at the majority of our existing generating facilities to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic life. On July 19, 2011, the EPA extended the public comment period for the new proposed Section 316(b) regulation by 30 days but stated its schedule for issuing a final rule remains July 27, 2012. 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. In November 2010, the Ohio EPA issued a permit for the coal-fired Bay Shore Plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. 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 Clean Water Act 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 August 5, 2011, EPA issued an information request pursuant to Sections 308 and 311 of the CWA for certain information pertaining to the oil spills and spill prevention measures at FirstEnergy facilities. FirstEnergy responded on October 10, 2011. On September 30, 2011, FirstEnergy executed tolling agreements with the EPA extending the statute of limitations to April 30, 2012. FGCO does not anticipate any losses resulting from this matter to be material.

In May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash disposal site at the Albright coal-fired plant seeking unspecified civil penalties and injunctive relief. MP is currently seeking relief from the arsenic limits through WVDEP agency review. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served another 60-Day Notice of Intent required prior to filing a citizen suit under the Clean Water Act for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Station.

FirstEnergy intends to vigorously defend against the CWA matters described above but cannot predict their outcomes.

Table of Contents

Monongahela River Water Quality

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 Hatfield's Ferry coal-fired plant. These criteria are reflected in the current PA DEP water discharge permit for that project. AE Supply appealed the PA DEP's permitting decision, which would require it to incur significant costs or negatively affect its ability to operate the scrubbers as designed. Preliminary studies indicate an initial capital investment in excess of $150 million in order to install technology to meet the TDS and sulfate limits in the permit. The permit has been independently appealed by Environmental Integrity Project and Citizens Coal Council, which seeks to impose more stringent technology-based effluent limitations. Those same parties have intervened in the appeal filed by AE Supply, and both appeals have been consolidated for discovery purposes. An order has been entered that stays the permit limits that AE Supply has challenged while the appeal is pending. A hearing on the parties' appeals was scheduled to begin in September 2011, however the Court stayed all prehearing deadlines on July 15, 2011 to allow the parties additional time to work out a settlement, and has rescheduled a hearing, if necessary, for July 2012. If these settlement discussions are successful, AE Supply anticipates that its obligations will not be material. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals.

In a parallel rulemaking, 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 only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

In December 2010, PA DEP submitted its Clean Water Act 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 its Hatfield's Ferry and Mitchell facilities in Pennsylvania and its Fort Martin facility in West Virginia.

In October 2009, the WVDEP issued the water discharge permit for the Fort Martin generation facility. Similar to the Hatfield's Ferry water discharge permit issued for the scrubber project, the Fort Martin permit imposes effluent limitations for TDS and sulfate concentrations. The permit also imposes temperature limitations and other effluent limits for heavy metals that are not contained in the Hatfield's Ferry water permit. Concurrent with the issuance of the Fort Martin permit, WVDEP also issued an administrative order that sets deadlines for MP to meet certain of the effluent limits that are effective immediately under the terms of the permit. MP appealed the Fort Martin permit and the administrative order. The appeal included a request to stay certain of the conditions of the permit and order while the appeal is pending, which was granted pending a final decision on appeal and subject to WVDEP moving to dissolve the stay. The appeals have been consolidated. MP moved to dismiss certain of the permit conditions for the failure of the WVDEP to submit those conditions for public review and comment during the permitting process. An agreed-upon order that suspends further action on this appeal, pending WVDEP's release for public review and comment on those conditions, was entered on August 11, 2010. The stay remains in effect during that process. The current terms of the Fort Martin permit would require MP to incur significant costs or negatively affect operations at Fort Martin. Preliminary information indicates an initial capital investment in excess of the capital investment that may be needed at Hatfield's Ferry in order to install technology to meet the TDS and sulfate limits in the Fort Martin permit, which technology may also meet certain of the other effluent limits in the permit. Additional technology may be needed to meet certain other limits in the permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals.

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 February 2009, the EPA requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

In December 2009, in an advanced 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. 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 our results of operations and financial condition.

LBR CCB impoundment is expected to run out of disposal capacity for disposal of CCBs from the BMP between 2016 and 2018. In July 2011, BMP submitted a Phase I permit application to PA DEP for construction of a new dry CCB disposal facility adjacent to LBR. BMP anticipates submitting zoning applications for approval to allow construction of a new dry CCB disposal facility prior to commencing construction.

Table of Contents

The Utility Registrants have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. 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, 2011, based on estimates of the total costs of cleanup, the Utility Registrants' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $103 million (JCP&L - $69 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FirstEnergy - $31 million) have been accrued through September 30, 2011. Included in the total are accrued liabilities of approximately $63 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. On July 11, 2011, FirstEnergy was found to be a potentially responsible party under CERCLA indirectly liable for a portion of past and future clean-up costs at certain legacy MGP sites, estimated to total approximately $59 million. FirstEnergy recognized an additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011. FirstEnergy determined that it is reasonably possible that it or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses at those sites cannot be determined or reasonably estimated.

(C) OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court's decision decertifying the class. In November 2010, the Supreme Court issued an order denying Plaintiffs' motion for leave to appeal. The Court's order effectively ends the attempt to certify the class, and leaves only nine (9) plaintiffs to pursue their respective individual claims. The matter was referred back to the lower court, which set a trial date for February 13, 2012 for the remaining individual plaintiffs. Plaintiffs have accepted an immaterial amount in final settlement of all matters and the settlement documentation is being finalized for execution by all parties.

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of September 30, 2011, 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. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of nuclear facilities. On March 28, 2011, FENOC submitted its biennial report on nuclear decommissioning funding to the NRC. This submittal identified a total shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry of approximately $92.5 million. On June 24, 2011, FENOC submitted a $95 million parental guarantee to the NRC for its approval.

In January 2004, subsidiaries of FirstEnergy filed a lawsuit in the U.S. Court of Federal Claims seeking damages in connection with costs incurred at the Beaver Valley, Davis-Besse and Perry nuclear facilities as a result of the DOE's failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to begin accepting spent nuclear fuel by the Nuclear Waste Policy Act (42 USC 10101 et seq) and the contracts entered into by the DOE and the owners and operators of these facilities pursuant to the Act. On January 18, 2011, the parties, FirstEnergy and DOJ, filed a joint status report that established a schedule for the litigation of these claims. FirstEnergy filed damages schedules and disclosures with the DOJ on February 11, 2011, seeking damages for delay costs incurred through September 30, 2010. The damage claim is subject to review and audit by DOE.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station 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. By this order, the ASLB also admitted two contentions challenging whether FENOC's Environmental Report adequately evaluated (1) a combination of renewable energy sources as alternatives to the renewal of Davis-Besse's operating license, and (2) severe accident mitigation alternatives at Davis-Besse. On May 6, 2011, FENOC filed an appeal with the NRC Commissioners from the order granting a hearing on the Davis-Besse license renewal application.

On April 14, 2011, a group of environmental organizations petitioned the NRC Commissioners to suspend certain pending nuclear licensing proceedings, including the Davis-Besse license renewal proceeding, to ensure that any safety and environmental implications of the accident at the Fukushima Daiichi Nuclear Power Station in Japan are considered. In a September 11, 2011 order, the NRC denied the request to suspend the licensing proceedings and referred to the NRC Task Force conducting a “Near-Term Evaluation of the Need for Agency Actions Following the Events in Japan” for those portions of the petitions requesting

Table of Contents

rulemaking.

On October 1, 2011, the Davis-Besse Plant 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 replaces a head installed in 2002, enhances safety, reliability and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, a sub-surface hairline crack was identified in one of the exterior architectural elements on the Shield Building, following opening of the building for installation of the new reactor head. 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. The team of industry-recognized structural concrete experts and Davis-Besse engineers evaluating this condition has determined the cracking does not affect the facility's structural integrity or safety. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in two localized areas of the Shield Building similar to those found in the architectural elements. FENOC has determined these two areas are not associated with the architectural element cracking and are investigating them as a separate issue. FENOC's overall investigation and analysis continues. Davis-Besse is currently expected to return to service around the end of November.

By a 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 a supplemental 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.

On October 2, 2011, FENOC completed the controlled shutdown of the Perry plant due to the loss of a startup transformer. On October 11, 2011, FENOC submitted a Technical Specification change request to the NRC to clarify that a delayed access circuit is temporarily qualified for use as one of the required offsite power circuits. By a letter dated October 17, 2011, NRC authorized Perry to operate with a delayed access circuit for offsite power until December 12, 2011. Concurrently, a spare replacement transformer from Davis-Besse was transported to Perry for modification and installation.

In light of the impacts of the earthquake and tsunami on the reactors in Fukushima, Japan, the NRC conducted inspections of emergency equipment at US reactors. The NRC also established a Near-Term Task Force to review its processes and regulations in light of the incident, and, on July 12, 2011, the Task Force issued its report of recommendations for regulatory changes. On October 18, 2011, the NRC approved the Staff recommendations, and directed the Staff to implement its near-term recommendations without delay. Ultimately, the adoption of the Staff recommendations on near-term actions is likely to result in additional costs to implement plant modifications and upgrades required by the regulatory process over the next several years, which costs are likely to be material.

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). Post-trial filings occurred in May

2011, with Oral Argument on June 28, 2011. On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, ICG posted bond and filed a Notice of Appeal and a briefing schedule was issued with oral argument likely in May of 2012. AE Supply and MP intend to vigorously pursue this matter through appeal if necessary but cannot predict its outcome.

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 was approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

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

Table of Contents

are described under Note 11, Regulatory Matters below.

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 an obligation, it discloses such obligations with 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.

11. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FGCO, FENOC, ATSI and TrAIL. The NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by the RFC.

FirstEnergy believes that it generally 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, the 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. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to RFC a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, RFC issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to RFC on September 27, 2010. On July 8, 2011, RFC and Met-Ed signed a settlement agreement to resolve all outstanding issues related to the vegetation encroachment event. The settlement calls for Met-Ed to pay a penalty of $650,000, and for FirstEnergy to perform certain mitigating actions. These mitigating actions include inspecting FirstEnergy's transmission system using LiDAR technology, and reporting the results of inspections, and any follow-up work, to RFC. FirstEnergy was performing the LiDAR work in response to certain other industry directives issued by NERC in 2010. NERC subsequently approved the settlement agreement and, on September 30, 2011, submitted the approved settlement to FERC for final approval. FERC approved the settlement agreement on October 28, 2011.

(B) MARYLAND

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a five-year cycle (to begin in 2008) for the MDPSC to report to the legislature on the status of SOS. PE now conducts rolling auctions to procure the power supply necessary to serve its customer load pursuant to a plan approved by the MDPSC. However, the terms on which PE will provide SOS to residential customers after the settlement beyond 2012 will depend on developments with respect to SOS in Maryland between now and then, including but not limited to possible MDPSC decisions in the proceedings discussed below.

The MDPSC opened a new docket in August 2007 to consider matters relating to possible “managed portfolio” approaches to SOS and other matters. “Phase II” of the case addressed utility purchases or construction of generation, bidding for procurement of demand response resources and possible alternatives if the TrAIL and PATH projects were delayed or defeated. It is unclear when the MDPSC will issue its findings in this proceeding.
In September 2009, the MDPSC opened a new proceeding to receive and consider proposals for construction of new generation

resources in Maryland. In December 2009, Governor Martin O'Malley filed a letter in this proceeding in which he characterized the electricity market in Maryland as a "failure" and urged the MDPSC to use its existing authority to order the construction of new generation in Maryland, vary the means used by utilities to procure generation and include more renewables in the generation mix. In August 2010, the MDPSC opened another new proceeding to solicit comments on the PJM RPM process. Public hearings on the comments were held in October 2010. In December 2010, the MDPSC issued an order soliciting comments on a model request for proposal for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and on September 29, 2011, the MDPSC issued an order requiring the utilities to issue the RFP crafted by the MDPSC by October 7, 2011. The RFPs were issued by the utilities as ordered by the MDPSC. The order indicated that bids were due by November 11, 2011, that the MDPSC would be the entity evaluating all bids, and that a hearing on whether to require the purchase of generation in light of the bids would be held on January 31, 2012, after receipt of further comments from all interested parties on January 13, 2012.

In September 2007, the MDPSC issued an order that required the Maryland utilities to file detailed plans for how they will meet the "EmPOWER Maryland" proposal that electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals. In 2008, PE filed its comprehensive plans for attempting to achieve those goals, asking the MDPSC to approve programs for residential, commercial, industrial, and governmental customers, as well as a customer education program. The MDPSC ultimately approved the programs in August 2009 after certain modifications had been made as required by the MDPSC, and approved cost recovery for the programs in October 2009. Expenditures were estimated to be approximately $101 million and would be recovered over the following six years. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, PE's plans for additional and improved programs for the period 2012-2014 were filed on August 31, 2011. Hearings on those plans and the plans of the other utilities were held in mid October 2011.

In March 2009, the MDPSC issued an order temporarily suspending the right of all electric and gas utilities in the state to terminate service to residential customers for non-payment of bills. The MDPSC subsequently issued an order making various rule changes relating to terminations, payment plans, and customer deposits that make it more difficult for Maryland utilities to collect deposits or to terminate service for non-payment. The MDPSC is continuing to conduct hearings and collect data on payment plan and related issues and has adopted regulations that expand the summer and winter "severe weather" termination moratoria when temperatures are very high or very low, from one day, as provided by statute, to three days on each occurrence.

On March 24, 2011, the MDPSC held an initial hearing to discuss possible new regulations relating to service interruptions, storm response, call center metrics, and related reliability standards. The proposed rules included provisions for civil penalties for non-compliance. Numerous parties filed comments on the proposed rules and participated in the hearing, with many noting issues of cost and practicality relating to implementation. The Maryland legislature passed a bill on April 11, 2011, which requires the MDPSC to promulgate rules by July 1, 2012 that address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. In crafting the regulations, the legislation directs the MDPSC to 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 to assess each utility's compliance with the standards, and may assess penalties of up to $25,000 per day per violation. The MDPSC convened a working group of utilities, regulators, and other interested stakeholders to address the topics of the proposed rules. A draft of the rules was filed, along with the report of the working group, on October 27, 2011. Comments on the draft rules are due by November 16, and a hearing to consider the rules and comments is scheduled for December 8 and 9, 2011. Separately, on July 7, 2011, the MDPSC adopted draft rules requiring monitoring and inspections for contact voltage. The draft rules were published in September, and then approved by the MDPSC as final rules on October 31, 2011. The rules will go into effect after being published again in the Maryland Register.

(C) NEW JERSEY

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 requests 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. JCP&L filed an answer to the Petition on September 28, 2011, stating, inter alia, that the Division of Rate Counsel analysis upon which it premises its Petition contains errors and inaccuracies, that JCP&L's achieved return on equity is currently within a reasonable range, and that there is no reason for the NJBPU to require JCP&L to file a base rate case at this time. The matter is pending before the NJBPU.

On September 22, 2011, the NJBPU ordered that JCP&L hire a Special Reliability Master, subject to NJBPU approval, to evaluate JCP&L's design, operating, maintenance and performance standards as they pertain to the Morristown, New Jersey underground electric distribution system, and make recommendations to JCP&L and the NJBPU on the appropriate courses of action necessary to ensure adequate reliability and safety in the Morristown underground network. A schedule for the completion of the Special Reliability Master's activities has not yet been established.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held on September 26 and 27,

Table of Contents

2011, to solicit public comments regarding the state of preparedness and responsiveness of the local electric distribution companies prior to, during and after Hurricane Irene. By subsequent Notice issued September 28, 2011, additional hearings were held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 2011 related to this inquiry. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

(D) 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 (initial auctions held on October 20, 2010 and January 25, 2011); a load cap of no less than 80%, 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, 2015 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.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required 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 the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The PUCO issued an Opinion and Order generally approving the Ohio Companies' 3-year plan, and the Companies are in the process of implementing those programs included in the Plan. OE fell short of its statutory 2010 energy efficiency and peak demand reduction benchmarks and therefore, on January 11, 2011, it requested that its 2010 energy efficiency and peak demand reduction benchmarks be amended to actual levels achieved in 2010. The PUCO granted this request on May 19, 2011 for OE, finding that the motion was moot for CEI and TE. Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Ohio Companies' 2010 (and 2011 and 2012) energy efficiency benchmarks when addressing the portfolio plan, the Ohio Companies were not certain of their 2010 energy efficiency obligations. Therefore, CEI and TE (each of which achieved its 2010 energy efficiency and peak demand reduction statutory benchmarks) also requested an amendment if and only to the degree one was deemed necessary to bring them into compliance with their yet-to-be-defined modified benchmarks. On June 2, 2011, the Companies filed an application for rehearing to clarify the decision related to CEI and TE. On July 27, 2011, the PUCO denied that application for rehearing, but clarified that CEI and TE could apply for an amendment in the future for the 2010 benchmarks should it be necessary to do so. 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. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Ohio Companies to recover all costs related to the original CFL program that the Ohio Companies had previously suspended at the request of the PUCO. Applications for Rehearing were filed on April 22, 2011, regarding portions of the PUCO's decision, including the method for calculating savings and certain changes made by the PUCO to specific programs. On September 7, 2011, the PUCO denied those applications for rehearing.

Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they served in 2009 and 0.50% of the KWH they served in 2010. 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 March 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market and reduced the Ohio Companies' aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies' 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. On April 15, 2011, the Ohio Companies filed an application seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio on the basis that an insufficient quantity of solar resources are available in the market but reflecting solar RECs that they have obtained and providing additional information regarding efforts to secure solar RECs. On August 3, 2011, the PUCO granted the Ohio Companies' force majeure request for 2010 and increased their 2011 benchmark by the amount of SRECs generated in Ohio that the Ohio Companies were short in 2010. On September 2, 2011, the Environmental Law and Policy Center and Nucor Steel Marion, Inc. filed applications for rehearing. The Ohio Companies filed their response on September 12, 2011. These applications for rehearing were denied by the PUCO on September 20, 2011, but as part of its Entry on Rehearing the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. Separately, one party has filed a request that the PUCO audit the cost of the Ohio Companies' compliance with the alternative energy requirements and the Ohio Companies' compliance with Ohio law. The PUCO has not ruled on this request.

In February 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. In March 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges

Table of Contents

in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect in March 2010. In April 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season and charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect in May 2010 and the proceeding remains open. The hearing on the matter was held in February 2011. The PUCO modified and approved the Ohio Companies' application on May 25, 2011, ruling that the new credit be applied only to customers that heat with electricity and be phased out over an eight-year period and granting authority for the Ohio Companies to recover deferred costs and associated carrying charges. OCC filed an application for rehearing on June 24, 2011 and the Ohio Companies filed their responses on July 5, 2011. The PUCO did not act on the application for rehearing within 30 days; thus, the application for rehearing is considered denied by operation of law. No appeal of this matter was filed and the time period in which to do so has expired.

(E) PENNSYLVANIA

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, directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. In March 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. The PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC's order, Met-Ed and Penelec filed plans to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges. Pursuant to the plan approved by the PPUC, Met-Ed and Penelec began to refund those amounts to customers in January 2011, and the refunds will continue over a 29 month period until the full amounts previously recovered for marginal transmission loses are refunded. In April 2010, Met-Ed and Penelec 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 Met-Ed's and Penelec's TSC riders. Met-Ed and Penelec filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court and also a complaint seeking relief in federal district court., which was subsequently amended. The PPUC filed a Motion to Dismiss Met-Ed's and Penelec's Amended Complaint on September 15, 2011. Met-Ed and Penelec filed a Responsive brief in Opposition to the PPUC's Motion to Dismiss on October 11, 2011. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million ($189 million for Met-Ed and $65 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

In each of May 2008, 2009 and 2010, the PPUC approved Met-Ed's and Penelec'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 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 Met-Ed's customers to provide for full recovery by December 31, 2010.

In February 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. In July 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC's Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn's June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

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, or 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. Act 129 also required utilities to file with the PPUC a SMIP.

The PPUC entered an Order in February 2010 giving final approval to all aspects of the EE&C Plans of Met-Ed, Penelec and Penn and the tariff rider became effective March 1, 2010. On February 18, 2011, the companies filed a petition to approve their First Amended EE&C Plans. On June 28, 2011, a hearing on the petition was held before an administrative law judge.

WP filed its original EE&C Plan in June 2009, which the PPUC approved, in large part, by Opinion and Order entered in October 2009. In September 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment, which the PPUC approved in January 2011.

On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes

Table of Contents

measures and a new program and implementation strategies consistent with the successful EE&C programs of Met-Ed, Penelec and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements.

Met-Ed, Penelec, Penn and WP submitted a preliminary status report on July 15, 2011, in which they reported on their compliance with statutory May 31, 2011 energy efficiency benchmarks. Preliminary results indicate that Met-Ed, Penelec and Penn will achieve their 2011 benchmarks; however WP may not. Final reports on actual results must be filed with the PPUC no later than November 15, 2011.

Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC in August 2009. This plan proposed a 24-month assessment period in which Met-Ed, Penelec and Penn will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs of approximately $29.5 million, which Met-Ed, Penelec and Penn, in their plan, proposed to recover through an automatic adjustment clause. The PPUC approved the SMIP, as modified by the ALJ, in June 2010. Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC's Order regarding the future ability to include smart meter costs in base rates, which the PPUC granted in part by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard, they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

In August 2009, WP filed its original SMIP, which provided for extensive deployment of smart meter infrastructure with replacement of all of WP's approximately 725,000 meters by the end of 2014. In December 2009, WP filed a motion to reopen the evidentiary record to submit an alternative smart meter plan proposing, among other things, a less-rapid deployment of smart meters.

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 smart meter deployment and certain smart meter dependent aspects of the EE&C Plan. In October 2010, WP and Pennsylvania's OCA filed a Joint Petition for Settlement addressing WP's smart meter implementation plan with the PPUC. Under the terms of the proposed settlement, 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. The proposed settlement also contemplates that WP 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 currently anticipates filing its plan for full-scale deployment of smart meters in June 2012. Under the terms of the proposed settlement, 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. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file in June 2012, or in a future base distribution rate case. Following additional proceedings, on March 9, 2011, WP submitted an Amended Joint Petition for Settlement which restates the Joint Petition for Settlement filed in October 2010, adds the PPUC's Office of Trial Staff as a signatory party, and confirms the support or non-opposition of all parties to the settlement. One party retained the ability to challenge the recovery of amounts spent on WP's original smart meter implementation plan. A Joint Stipulation with the OSBA was also filed on March 9, 2011. The PPUC approved the Amended Joint Petition for Full Settlement by order entered June 30, 2011.

By Tentative Order entered in September 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market will be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions. Met-Ed, Penelec, Penn Power and WP submitted joint comments on June 3, 2011. FES also submitted comments on June 3, 2011. On June 8, 2011, the PPUC conducted an en banc hearing on these issues at which both the Pennsylvania Companies and FES participated and offered testimony. A technical conference was held on August 10, 2011, and teleconferences are scheduled through December 14, 2011, to explore intermediate steps that can be taken to promote the development of a competitive market. An en banc hearing will be held on November 10, 2011. An intermediate work plan will be presented in December 2011 and a long range plan will be presented in the first quarter of 2012.

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

Table of Contents

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 calls for comments to be submitted within forty-five days of its publication in the Pennsylvania Bulletin, with no provision for replies. The Order has not been published yet. If implemented these rules could require a significant change in the way FES, Met-Ed, Penelec, Penn and WP do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition.

(F) WEST VIRGINIA

In 2009, the West Virginia Legislature enacted the Alternative and Renewable Energy Portfolio Act (Portfolio Act), which generally requires that a specified minimum percentage of electricity sold to retail customers in West Virginia by electric utilities each year be derived from alternative and renewable energy resources according to a predetermined schedule of increasing percentage targets, including ten percent by 2015, fifteen percent by 2020, and twenty-five percent by 2025. In November 2010, the WVPSC issued Rules Governing Alternative and Renewable Energy Portfolio Standard (RPS Rules), which became effective on January 4, 2011. Under the RPS Rules, on or before January 1, 2011, each electric utility subject to the provisions of this rule was required to prepare an alternative and renewable energy portfolio standard compliance plan and file an application with the WVPSC seeking approval of such plan. MP and PE filed their combined compliance plan in December 2010. A hearing was held at the WVPSC on June 13, 2011. An order was issued by the WVPSC in September 2011 which conditionally approved MP's and PE's compliance plan, contingent on the outcome of the resource credits case discussed below.

Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the Portfolio Act. Further, in February 2011, MP and PE filed a petition with the WVPSC seeking an Order declaring that MP is entitled to all alternative and renewable energy resource credits associated with the electric energy, or energy and capacity, that MP is required to purchase pursuant to electric energy purchase agreements between MP and three non-utility electric generating facilities in WV. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, has participated in the case in opposition to the Petition. A hearing was held at the WVPSC on August 25 and 26, 2011. An order is expected by the end of 2011.

In September 2011, MP and PE filed with the WVPSC to recover costs associated with fuel and purchased power (the ENEC) in the amount of $32 million which represents an approximate 3% overall increase in such costs over the past two years, primarily attributable to rising coal prices. The requested increase is partly offset by $2.5 million of synergy savings directly resulting from the merger of FirstEnergy and AE, which closed in February 2011. Under a cost recovery clause established by the WVPSC in 2007, MP and PE customer bills are adjusted periodically to reflect upward or downward changes in the cost of fuel and purchased power. The utilities' most recent request to recover costs for fuel and purchased power was in September 2009. A hearing on this matter is scheduled for November 29 - 30, 2011.

(G) FERC MATTERS

Rates for Transmission Service Between MISO and PJM

In November 2004, FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as SECA) during a 16-month transition period. In 2005, FERC set the SECA for hearing. The presiding ALJ issued an initial decision in August 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision was subject to review and approval by FERC. In May 2010, FERC issued an order denying pending rehearing requests and an Order on Initial Decision which reversed the presiding ALJ's rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. In July 2010, a petition for review of the order denying pending rehearing requests was filed at the U.S. Court of Appeals for the D.C. Circuit. In a subsequent compliance filing submitted to the FERC in August 2010, the Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy thereafter executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy's liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon settlements were approved by FERC in November 2010, and the respective payments made. The subsidiaries of Allegheny entered into nine settlements to fix their liability for SECA charges with various parties. All of the settlements were approved by FERC and the respective payments have been made for eight of the settlements. Payments due under the remaining settlement will be made as a part of the refund obligations of the Utilities that are under review by FERC as part of a compliance filing. Potential refund obligations of FirstEnergy and the Allegheny subsidiaries are not expected to be material. On September 30, 2011, the FERC issued an order denying all requests for rehearing of the May 2010 Order on Initial Decision, affirming that prior order in all respects.

Table of Contents

PJM Transmission Rate

In April 2007, FERC issued an order (Opinion 494) finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, FERC directed 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. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology, which is generally referred to as a "beneficiary pays" approach to allocating the cost of high voltage transmission facilities.

FERC's Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision in August 2009. The court affirmed FERC's ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on this finding, remanded the rate design issue to FERC.

In an order dated January 21, 2010, FERC set the matter for a "paper hearing"-- meaning that FERC called for parties to submit written comments pursuant to the schedule described in the order. FERC identified nine separate issues for comments and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM's filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain load serving entities in PJM bearing the majority of the costs. 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 commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by FERC.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone entered into 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.

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM's tariffs. On April 1, 2011, the MISO Transmission Owners (including ATSI) filed proposed tariff language that describes the mechanics of collecting and administering MTEP costs from ATSI-zone ratepayers. From March 20, 2011 through April 1, 2011, FirstEnergy, PJM and the MISO submitted numerous filings for the purpose of effecting movement of the ATSI zone to PJM on June 1, 2011. These filings include amendments to the MISO's tariffs (to remove the ATSI zone), submission of load and generation interconnection agreements to reflect the move into PJM, and submission of changes to PJM's tariffs to support the move into PJM.

On May 31, 2011, FERC issued orders that address the proposed ATSI transmission rate, and certain parts of the MISO tariffs that reflect the mechanics of transmission cost allocation and collection. In its May 31, 2011 orders, FERC approved ATSI's proposal to move the ATSI formula rate into the PJM tariff without significant change. Speaking to ATSI's proposed treatment of the MISO's exit fees and charges for transmission costs that were allocated to the ATSI zone, FERC required ATSI to present a cost-benefit study that demonstrates that the benefits of the move for transmission customers exceed the costs of any such move, which FERC had not previously required. Accordingly, FERC ruled that these costs must be removed from ATSI's proposed transmission rates until such time as ATSI files and FERC approves the cost-benefit study. On June 30, 2011, ATSI submitted the compliance filing that removed the MISO exit fees and transmission cost allocation charges from ATSI's proposed transmission rates. Also on June 30, 2011, ATSI requested rehearing of FERC's decision to require a cost-benefit study analysis as part of FERC's evaluation of ATSI's proposed transmission rates. Finally, and also on June 30, 2011, the MISO and the MISO TOs filed a competing compliance filing - one that would require ATSI to pay certain charges related to construction and operation of transmission projects within the MISO even though FERC ruled that ATSI cannot pass these costs on to ATSI's customers. ATSI on the one hand, and the MISO and MISO TOs on the other have, submitted subsequent filings - each of which is intended to refute the other's claims. ATSI's compliance filing and request for rehearing, as well as the pleadings that reflect the dispute between ATSI and the MISO/MISO TOs, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI's move into PJM. These orders approve ATSI's proposed interconnection agreements for large wholesale transmission customers and generators, and revisions to the PJM and MISO tariffs that reflect ATSI's move into PJM. In addition, FERC approved an “Exit Fee Agreement” that memorializes the agreement between ATSI and MISO with regard to ATSI's obligation to pay certain administrative charges to the MISO upon exit. Finally, ATSI and the MISO were able to negotiate an agreement of ATSI's responsibility for certain charges associated with long term firm transmission rights - that, according to the MISO, were payable by the ATSI zone upon its departure from the MISO. ATSI did not and does not agree that these costs should be charged to ATSI but, in order to settle the case and all claims associated with the case, ATSI agreed to a one-time payment of $1.8 million to the MISO. This settlement agreement has been submitted for FERC's review and approval. The final outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

Table of Contents

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners jointly filed with FERC their 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 formal transmission planning process (the MTEP). The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be "wheeled through" the MISO as well as to energy transactions that "source" in the MISO but "sink" outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO's Board approved the first MVP project -- the "Michigan Thumb Project." Under MISO's proposal, the costs of MVP projects 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 FirstEnergy. MISO estimated that approximately $15 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

In September 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO's proposal to allocate costs of MVPs projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the "beneficiary pays" approach). FirstEnergy also argued that, in light of progress that had been made to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO's MVP proposal.

In December 2010, FERC issued an order approving the MVP proposal without significant change. FERC's order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO's tariffs obligate ATSI to pay all charges that attached prior to ATSI's exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC's order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy requested rehearing of FERC's order. In its rehearing request, FirstEnergy argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. On October 21, 2011, FERC issued its order on rehearing. In the order, FERC noted that if liability for MVP costs were attached to ATSI prior to ATSI's exit, then ATSI would be responsible to pay the MVP charges. However, FERC did not address the question of whether liability for MVP costs should attach to ATSI. FirstEnergy is evaluating FERC's October 21, 2011 order, and continues to assess its future course of action.

As noted above, on February 1, 2011, ATSI filed proposed transmission rates related to its move into PJM. The proposed rates included line items that were intended to recover all MVP costs (if any) that might be charged to ATSI or to the ATSI zone. In its May 31, 2011 order on ATSI's proposed transmission rate FERC ruled that ATSI must submit a cost-benefit study before ATSI can recover the MVP costs. FERC further directed that ATSI remove the line-items from ATSI's formula rate that would recover the MVP costs until such time as ATSI submits and FERC approves the cost-benefit study. ATSI requested a rehearing of these parts of FERC's order and, pending this further legal process, has removed the MVP line items from its transmission rates.

On August 3, 2011, FirstEnergy filed a complaint with FERC based on the FERC's December 20, 2010, ruling. In the complaint, FirstEnergy argued that ATSI perfected the legal and financial requirements necessary to exit MISO before any MVP responsibilities could attach and asked FERC to rule that MISO cannot charge ATSI for MVP costs. On September 2, 2011, MISO, its TOs and other parties, filed responsive pleadings. MISO and its TOs argued that liability to pay for a single MVP project (the Michigan Thumb Project) attached to ATSI, before ATSI was able to exit MISO, and argued that FERC should order ATSI to pay a pro rata amount of the Michigan Thumb Project costs. On September 19, 2011, ATSI filed an answer stating its view that there are no legal or factual bases to charge the Michigan Thumb Project costs to ATSI. The complaint, and all subsequent pleadings, are pending before FERC. The October 21, 2011, FERC Order referenced above did not mention ATSI's rehearing order in the MVP docket. On October 31, 2011, FirstEnergy filed notice of its plans to appeal FERC's October 21, 2011, Order with the D.C. Circuit Court of Appeals.

FirstEnergy cannot predict the outcome of these proceedings at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the United States Court of Appeals for the Ninth Circuit in pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit has since remanded one of those proceedings to FERC, which arises out of claims previously filed with FERC by the California Attorney General on behalf of certain California parties against various sellers in the California wholesale power market, including AE Supply (the Lockyer case). AE Supply and several other sellers filed motions to dismiss the Lockyer case. In March 2010, the judge assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. On May 4, 2011, FERC affirmed the judge's ruling. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. The request for rehearing remains

Table of Contents

pending.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second complaint with FERC against various sellers, including AE Supply (the Brown case), again seeking refunds for trades in the California energy markets during 2000 and 2001. The above-noted trades with CDWR are the basis for including AE Supply in this new complaint. AE Supply filed a motion to dismiss the Brown complaint that was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. That request for rehearing also remains pending. FirstEnergy cannot predict the outcome of either of the above matters.

PATH Transmission Project

The PATH Project is comprised of a 765 kV transmission line that was proposed to extend from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland.

PJM initially authorized construction of the PATH Project in June 2007. In December 2010, PJM advised that its 2011 Load Forecast Report included load projections that are different from previous forecasts and that may have an impact on the proposed in-service date for the PATH Project. As part of its 2011 RTEP, and in response to a January 19, 2011 directive by a Virginia Hearing Examiner, PJM conducted a series of analysis using the most current economic forecasts and demand response commitments, as well as potential new generation resources. Preliminary analysis revealed the expected reliability violations that necessitated the PATH Project had moved several years into the future. Based on those results, PJM announced on February 28, 2011 that its Board of Managers had decided to hold the PATH Project in abeyance in its 2011 RTEP and directed FirstEnergy and AEP, as the sponsoring transmission owners, to suspend current development efforts on the project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the need for the project as part of its continuing RTEP process. PJM stated that its action did not constitute a directive to FirstEnergy and AEP to cancel or abandon the PATH Project. PJM further stated that it will complete a more rigorous analysis of the PATH Project and other transmission requirements and its Board will review this comprehensive analysis as part of its consideration of the 2011 RTEP. On February 28, 2011, affiliates of FirstEnergy and AEP filed motions or notices to withdraw applications for authorization to construct the project that were pending before state commissions in West Virginia, Virginia and Maryland. Withdrawal was deemed effective upon filing the notice with the MDPSC. The WVPSC and VSCC have granted the motions to withdraw.

PATH, LLC submitted a filing to FERC to implement a formula rate tariff effective March 1, 2008. In a November 19, 2010 order (November 19 Order) addressing various matters relating to the formula rate, FERC set the project's base return on equity for hearing and reaffirmed its prior authorization of a return on CWIP, recovery of start-up costs and recovery of abandonment costs. In the order, FERC also granted a 1.5% return on equity incentive adder and a 0.5% return on equity adder for RTO participation. These adders will be applied to the base return on equity determined as a result of the hearing. The PATH Companies, Joint Intervenors, Joint Consumer Advocates and FERC staff have agreed to a four year moratorium. A settlement was reached, which reflects a base ROE of 10.4% (plus authorized adders) effective January 1, 2011. Accordingly, the revised ROE will be reflected in a revised Projected Transmission Revenue Requirement for 2011 with true-up occurring in 2013. The FirstEnergy portion of the refund for March 1, 2008 through December 31, 2010 is approximately $2 million (inclusive of interest). The refund amount was computed using a base ROE of 10.8% plus authorized adders. On October 7, 2011 PATH and six intervenors submitted to FERC an unopposed settlement agreement. Contemporaneous with this submission, PATH LLC and the six intervenors filed with the Chief Administrative Law Judge of FERC a joint motion for interim approval and authorization to implement the refund on an interim basis pending issuance of a FERC order acting on the settlement agreement. On October 12, 2011, the motion for interim approval and authorization to implement the refund was granted by the Chief Administrative Law Judge. FERC has not acted on the settlement agreement.

Seneca Pumped Storage Project Relicensing

The Seneca (Kinzua) 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 PAD in the license docket.

On November 30, 2010, the Seneca Nation of Indians filed its notice of intent to relicense and PAD documents necessary for them 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.

Table of Contents

On September 11, 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 September 26, 2011, third parties submitted comments regarding the parties' respective “Revised Study Plan” documents. On September 26, 2011, FirstEnergy submitted comments regarding certain factual and legal matters asserted in the Seneca Nation's Revised Study Plan document. On October 7, 2011, FirstEnergy submitted further comments to refute certain factual and legal arguments that were advanced by the Seneca Nation in comments that were submitted on September 26, 2011. On October 11, 2011, FERC Staff issued letters that finalize the studies that are to be performed. FirstEnergy and the Seneca Nation each will perform the studies described in the October 11, 2011 Staff determination. The study process will run through approximately November of 2013.

FirstEnergy cannot predict the outcome of these proceedings at this time.

12. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four types of stock-based compensation programs — LTIP, EDCP, ESOP and DCPD, as described below.

Allegheny’s stock-based awards were converted into FirstEnergy stock-based awards as of the date of the merger. These awards, referred to below as converted Allegheny awards, were adjusted in terms of the number of awards and, where applicable, the exercise price thereof, to reflect the merger’s common stock exchange ratio of 0.667 of a share of FirstEnergy common stock for each share of AE common stock.

(A) LTIP

FirstEnergy’s LTIP includes four forms of stock-based compensation awards — stock options, performance shares, restricted stock and restricted stock units.

Under FirstEnergy’s LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to be settled in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be settled in cash rather than common stock and therefore do not count against the limit on stock-based awards. There were 5.6 million shares available for future awards under the LTIP as of September 30, 2011.

Restricted Stock and Restricted Stock Units

Restricted common stock (restricted stock) and restricted stock unit (stock unit) activity for the nine months ended September 30, 2011, was as follows:

	Nine Months Ended September 30, 2011
Restricted stock and stock units outstanding as of January 1, 2011	1,878,022
Granted	907,898
Converted AE restricted stock	645,197
Exercised	(435,358)
Forfeited	(213,039)
Restricted stock and stock units outstanding as of September 30, 2011	2,782,720

The 907,898 shares of restricted common stock granted during the nine months ended September 30, 2011, had a grant-date fair value of $33.8 million and a weighted-average vesting period of 2.76 years.

Restricted stock units include awards that will be settled in a specific number of shares of common stock after the service condition has been met. Restricted stock units also include performance-based awards that will be settled after the service condition has been met in a specified number of shares of common stock based on FirstEnergy’s performance compared to annual target performance metrics.

Compensation expense recognized during the nine months ended September 30, 2011 and 2010, for restricted stock and restricted stock units, net of amounts capitalized, was approximately $43 million and $40 million, respectively.

Stock Options

Stock option activity for the nine months ended September 30, 2011 was as follows:

Table of Contents

Stock Option Activities	Number of Shares	Weighted Average Exercise Price
Stock options outstanding as of January 1, 2011 (all exercisable)	2,889,066	$35.18
Options granted	662,122	37.75
Converted AE options	1,805,811	41.75
Options exercised	(847,261)	31.20
Options forfeited/expired	(110,085)	71.65
Stock options outstanding as of September 30, 2011 (3,737,531 options exercisable)	4,399,653	$38.12

Compensation expense recognized for stock options during the nine months ended September 30, 2011, was $0.5 million. No expense was recognized during the nine months ended September 30, 2010. Options granted during the nine months ended September 30, 2011, had a grant-date fair value of $3.3 million and an expected weighted-average vesting period of 3.79 years.

Options outstanding by exercise price as of September 30, 2011, were as follows:

Exercise Prices	Shares Under Options	Weighted Average Exercise Price	Remaining Contractual Life in Years
$20.02 – $30.74	987,607	$26.83	1.77
$30.89 – $40.93	3,061,503	37.36	3.96
$42.72 – $51.82	3,883	51.02	0.45
$53.06 – $62.97	41,219	53.94	2.90
$64.52 – $71.82	8,671	67.53	4.05
$73.39 – $80.47	294,102	80.22	3.71
$81.19 – $89.59	2,668	85.39	2.81
Total	4,399,653	$38.12	3.44

Performance Shares

Performance shares will be settled in cash and are accounted for as liability awards. Compensation expense (income) recognized for performance shares during the nine months ended September 30, 2011 and 2010, net of amounts capitalized, totaled $2 million and $(8) million, respectively. No performance shares under the FirstEnergy LTIP were settled during the nine months ended September 30, 2011 and 2010.

(B) ESOP

During 2011, shares of FirstEnergy common stock were purchased on the open market and contributed to participants' accounts. Total ESOP-related compensation expense for the nine months ended September 30, 2011 and 2010, net of amounts capitalized and dividends on common stock, was approximately $34 million and $31 million, respectively.

(C) EDCP

There was no material compensation expense recognized on EDCP stock units during the nine months ended September 30, 2011, and 2010.

(D) DCPD

DCPD expenses recognized during the nine months ended September 30, 2011, and 2010 were approximately $3 million in each period. The net liability recognized for DCPD of approximately $6 million as of September 30, 2011, is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

Of the 1.7 million stock units authorized under the EDCP and DCPD, 1,075,080 stock units were available for future awards as of September 30, 2011.

13. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

In May 2011, the FASB amended authoritative accounting guidance regarding fair value measurement. The amendment prohibits the application of block discounts for all fair value measurements, permits the fair value of certain financial instruments to be measured on the basis of the net risk exposure and allows the application of premiums or discounts to the extent consistent with the applicable unit of account. The amendment clarifies that the highest-and-best use and valuation-premise concepts are not relevant to financial instruments. Expanded disclosures are required under the amendment, including quantitative information about

Table of Contents

significant unobservable inputs used for Level 3 measurements, a qualitative discussion about the sensitivity of recurring Level 3 measurements to changes in unobservable inputs disclosed, a discussion of the Level 3 valuation processes, any transfers between Levels 1 and 2 and the classification of items whose fair value is not recorded but is disclosed in the notes. The amendment is effective for FirstEnergy in the first quarter of 2012. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In June 2011, the FASB issued new accounting guidance that revises the manner in which entities present comprehensive income in their financial statements. The new guidance requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. The new guidance does not change the items that must be reported in other comprehensive income and does not affect the calculation or reporting of earnings per share. The amendment is effective for FirstEnergy in the first quarter of 2012. This amendment will not have a material effect on FirstEnergy's financial statements.

In September 2011, the FASB amended guidance regarding how entities test goodwill for impairment. Under the revised guidance, an entity is not required to calculate the fair value of a reporting unit unless the entity determines that it is more likely than not that its fair value is less than its carrying amount, including goodwill. The revised guidance is intended to reduce the cost and complexity of performing goodwill impairment tests and is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. FirstEnergy will adopt the new guidance for goodwill impairment tests performed after calendar year 2011 and does not expect that the adoption will have a significant impact on its financial statements.

14. SEGMENT INFORMATION

With the completion of the AE merger in the first quarter of 2011, FirstEnergy reorganized its management structure, which resulted in changes to its operating segments to be consistent with the manner in which management views the business. The new structure supports the combined company's primary operations — distribution, transmission, generation and the marketing and sale of its products. The external segment reporting is consistent with the internal financial reporting used by FirstEnergy's chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. FirstEnergy now has three reportable operating segments — Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services.

Prior to the change in composition of business segments, FirstEnergy's business was comprised of two reportable operating segments. The Energy Delivery Services segment was comprised of FirstEnergy's then eight existing utility operating companies that transmit and distribute electricity to customers and purchase power to serve their POLR and default service requirements. The Competitive Energy Services segment was comprised of FES, which supplies electric power to end-use customers through retail and wholesale arrangements. The "Other/Corporate" amounts consisted of corporate items and other businesses that were below the quantifiable threshold for separate disclosure. Disclosures for FirstEnergy's operating segments for 2010 have been reclassified to conform to the current presentation.

The changes in FirstEnergy's reportable segments during 2011 consisted primarily of the following:

- Energy Delivery Services was renamed Regulated Distribution and the operations of MP, PE and WP, which were acquired as part of the merger with AE, and certain regulatory asset recovery mechanisms formerly included in the "Other" segment, were placed into this segment.
- A new Regulated Independent Transmission segment was created consisting of ATSI, and the operations of TrAIL and FirstEnergy's interest in PATH; TrAIL and PATH were acquired as part of the merger with AE. The transmission assets and operations of JCP&L, Met-Ed, Penelec, MP, PE and WP remained within the Regulated Distribution segment.
- AE Supply, an operator of generation facilities that was acquired as part of the merger with AE, was placed into the Competitive Energy Services segment.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately 6 million customers within 67,000 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 the transmission operations of JCP&L,

Met-Ed, Penelec, WP, MP and PE and the regulated electric generation facilities in West Virginia and New Jersey which MP and JCP&L, respectively, own or contractually control.

The Regulated Distribution segment's revenues are primarily derived from the delivery of electricity within FirstEnergy's service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (POLR, SOS or default service) in its Maryland, New Jersey, Ohio and Pennsylvania franchise areas. Its results reflect the commodity costs of securing electric generation from FES and AE Supply and from non-affiliated power suppliers and the deferral and amortization of certain fuel costs.

The Regulated Independent Transmission segment transmits electricity through transmission lines and its revenues are primarily derived from the formula rate recovery of costs and a return on investment for capital expenditures in connection with TrAIL, PATH

Table of Contents

and other projects and revenues from providing transmission services to electric energy providers, power marketers and receiving transmission-related revenues from operating a portion of the FirstEnergy transmission system. Its results reflect the net PJM and MISO transmission expenses related to the delivery of the respective generation loads. On June 1, 2011, the ATSI transmission assets previously dedicated to MISO were integrated into the PJM market. All of FirstEnergy's assets now reside in one RTO.

The Competitive Energy Services segment, through FES and AE Supply, supplies electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements of FirstEnergy's Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. FES purchases the entire output of the 18 generating facilities which it owns and operates through its FGCO subsidiary (fossil and hydroelectric generating facilities) and owns, through its NGC subsidiary, FirstEnergy's nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, operates and maintains NGC's nuclear generating facilities 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 with non-affiliates, pursuant to full output, cost-of-service PSAs. AE Supply together with its consolidated subsidiary, AGC owns, operates and controls the electric generation capacity of 18 facilities. AGC owns and sells generation capacity to AE Supply and MP, which own approximately 59% and 41% of AGC, respectively. AGC's sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. All of AGC's revenues are derived from sales of its 1,109 MW share of generation capacity from the Bath County generation facility to AE Supply and MP.

This Competitive Energy Services segment controls approximately 20,000 MWs of capacity and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from affiliated and non-affiliated 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.

Other/Corporate contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment.

Financial information for each of FirstEnergy's reportable segments is presented in the table below, which includes financial results for Allegheny beginning February 25, 2011. FES and the Utility Registrants do not have separate reportable operating segments.

Table of Contents

Segment Financial Information

Three Months Ended	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other/Corporate	Reconciling Adjustments	Consolidated
	(In millions)					
September 30, 2011						
External revenues	$2,934	$1,714	$106	$ (39)	$(9)	$4,706
Internal revenues	1	315	—	—	(303)	13
Total revenues	2,935	2,029	106	(39)	(312)	4,719
Depreciation and amortization	282	110	16	6	—	414
Investment income (loss), net	32	28	—	—	(12)	48
Net interest charges	144	73	12	21	—	250
Income taxes	170	136	20	(23)	8	311
Net income (loss)	288	232	34	(39)	(6)	509
Total assets	26,951	16,541	2,353	816	—	46,661
Total goodwill	5,551	897	—	—	—	6,448
Property additions	281	197	34	—	—	512
September 30, 2010						
External revenues	$2,685	$1,002	$73	$ (22)	$(10)	$3,728
Internal revenues	60	599	—	—	(659)	—
Total revenues	2,745	1,601	73	(22)	(669)	3,728
Depreciation and amortization	278	67	9	4	—	358
Investment income (loss), net	24	27	—	1	(6)	46
Net interest charges	125	33	6	7	(4)	167
Income taxes	124	(16)	13	(9)	7	119
Net income (loss)	202	(26)	22	(14)	(9)	175
Total assets	21,763	11,078	1,011	856	—	34,708
Total goodwill	5,551	24	—	—	—	5,575
Property additions	191	264	18	(2)	—	471
Nine Months Ended September 30, 2011						
External revenues	$7,687	$4,450	$278	$ (92)	$(25)	$12,298
Internal revenues	1	976	—	—	(920)	57
Total revenues	7,688	5,426	278	(92)	(945)	12,355
Depreciation and amortization	767	305	47	19	—	1,138
Investment income (loss), net	84	49	—	1	(34)	100
Net interest charges	420	195	32	61	—	708
Income taxes	334	146	45	(73)	38	490
Net income (loss)	568	249	78	(125)	(45)	725
Total assets	26,951	16,541	2,353	816	—	46,661
Total goodwill	5,551	897	—	—	—	6,448

Property additions	760	608	105	56	—	1,529
September 30, 2010						
External revenues	$7,483	$2,518	$189	$ (65)	$(24)	$10,101
Internal revenues	79	1,812	—	—	(1,824)	67
Total revenues	7,562	4,330	189	(65)	(1,848)	10,168
Depreciation and amortization	855	215	34	10	—	1,114
Investment income (loss), net	78	41	—	2	(28)	93
Net interest charges	373	99	16	29	(11)	506
Income taxes	267	101	27	(33)	2	364
Net income (loss)	437	164	45	(53)	(13)	580
Total assets	21,763	11,078	1,011	856	—	34,708
Total goodwill	5,551	24	—	—	—	5,575
Property additions	499	883	47	38	—	1,467

Reconciling adjustments primarily consist of elimination of intersegment transactions.

Table of Contents

15. IMPAIRMENTS AND LONG-LIVED ASSETS PENDING SALE

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value.

Fremont Energy Center

On March 11, 2011, FirstEnergy and American Municipal Power, Inc., entered into an agreement for the sale of Fremont Energy Center, which includes two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. The execution of this agreement triggered a need to evaluate the recoverability of the carrying value of the assets associated with the Fremont Energy Center. The estimated fair value of the Fremont Energy Center was based on the purchase price outlined in the sale agreement with American Municipal Power, Inc. The result of this evaluation indicated that the carrying cost of the Fremont Energy Center was not fully recoverable. As a result of the recoverability evaluation, FirstEnergy recorded an impairment charge of $11 million to operating income during the quarter ended March 31, 2011. On July 28, 2011, FirstEnergy closed the sale of Fremont Energy Center to American Municipal Power, Inc.

Peaking Facilities

During the first nine months of 2011, FirstEnergy assessed the carrying values of certain peaking facilities that will more likely than not be sold or disposed of before the end of their useful lives. The estimated fair values were based on estimated sales prices quoted in an active market. The result of this evaluation indicated that the carrying costs of the peaking facilities were not fully recoverable. FirstEnergy recorded impairment charges of $3 million and $23 million during the three and nine months ended September 30, 2011, respectively, as a result of the recoverability evaluation. On October 18, 2011, FirstEnergy closed on the sale of the Richland and Stryker Peaking Facilities which are capable of generating a total of 450 MW of peaking capacity.

Signal Peak

On October 18, 2011, FirstEnergy announced that a subsidiary of Gunvor Group, Ltd purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. As part of the transaction, FirstEnergy received approximately $257.5 million in proceeds and retained a 33-1/3% equity ownership in the joint venture. The transaction will result in an estimated after-tax gain of approximately $370 million, which includes a revaluation of its retained equity ownership. FirstEnergy previously consolidated this joint venture and, as a result of the sale, its retained 33-1/3% interest will be accounted for using the equity method of accounting.

As of September 30, 2011, assets and liabilities of the Signal Peak mining and transportation operations that were reclassified on FirstEnergy's Consolidated Balance Sheet include the following:

(In millions)	
Assets Pending Sale:	
Current assets	$17
Property, plant and equipment	369
Deferred charges and other assets	16
	402
Liabilities Related to Assets Pending Sale:	
Current liabilities	31
Long-term debt	360
Noncurrent liabilities	10
	401
Net Assets Pending Sale	$1

In addition, the Noncontrolling interest reported on FirstEnergy's Consolidated Balance Sheet as of September 30, 2011, included approximately $(50) million relating to the joint venture.

16. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and the associated cost of nuclear power plant decommissioning, reclamation of sludge disposal ponds and closure of coal ash disposal sites. In addition, FirstEnergy has recognized conditional asset retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES, OE and TE primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear

Table of Contents

generating facilities (OE for its leasehold interests in Beaver Valley Unit 2 and Perry and TE for its leasehold interest in Beaver Valley Unit 2). The ARO liabilities for JCP&L, Met-Ed and Penelec primarily relate to the decommissioning of the TMI-2 nuclear generating facility. FES, OE, TE, JCP&L, Met-Ed and Penelec use an expected cash flow approach to measure the fair value of their nuclear decommissioning ARO.

During the first quarter of 2011, studies were completed to update the estimated cost of decommissioning the Perry nuclear generating facility. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES and OE and reduced the liability for each subsidiary in the amounts of $40 million and $6 million, respectively.

During the second quarter of 2011, studies were completed to update the estimated cost of decommissioning the Davis-Besse nuclear facility. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES and reduced the liability for FES in the amount of $5 million.

The revisions to the estimated cash flows had no significant impact on accretion of the obligation during the three months and nine months ended September 30, 2011, when compared to the same periods of 2010.

17. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FGCO completed a sale and leaseback transaction for its 93.825% 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 for the three months and nine months ended September 30, 2011 and 2010, consolidating balance sheets as of September 30, 2011 and December 31, 2010 and consolidating statements of cash flows for the nine months ended September 30, 2011 and 2010 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.

Table of Contents

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Three Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
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	164	100	129	12	405
Provision for depreciation	1	32	37	(1)	69
General taxes	19	9	3	—	31
Impairment of long-lived assets	—	2	—	—	2
Total operating expenses	1,551	468	281	(1,024)	1,276
OPERATING INCOME (LOSS)	(106)	218	90	(11)	191
OTHER INCOME (EXPENSE):					
Investment income	—	—	28	—	28
Miscellaneous income (expense), including net income from equity investees	187	16	—	(194)	9
Interest expense — affiliates	—	(1)	(1)	—	(2)
Interest expense — other	(24)	(26)	(16)	15	(51)
Capitalized interest	—	3	5	—	8
Total other income (expense)	163	(8)	16	(179)	(8)
INCOME BEFORE INCOME TAXES	57	210	106	(190)	183
INCOME TAXES (BENEFITS)	(53)	82	42	2	73
NET INCOME	$110	$128	$64	$(192)	$110

79

Table of Contents

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Nine Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
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	485	333	460	37	1,315
Provision for depreciation	3	95	111	(4)	205
General taxes	46	28	17	—	91
Impairment of long-lived assets	—	22	—	—	22
Total operating expenses	4,624	1,371	926	(3,100)	3,821
OPERATING INCOME (LOSS)	(537)	593	307	(33)	330
OTHER INCOME (EXPENSE):					
Investment income	1	1	48	—	50
Miscellaneous income, including net income from equity investees	543	18	—	(544)	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)	471	(52)	12	(497)	(66)
INCOME (LOSS) BEFORE INCOME TAXES	(66)	541	319	(530)	264
INCOME TAXES (BENEFITS)	(232)	201	122	7	98
NET INCOME	$166	$340	$197	$(537)	$166

Table of Contents

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Three Months Ended September 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
REVENUES	$1,576	$645	$381	$(1,013)	$1,589
OPERATING EXPENSES:					
Fuel	13	329	49	—	391
Purchased power from affiliates	1,059	13	57	(1,013)	116
Purchased power from non-affiliates	446	—	—	—	446
Other operating expenses	84	96	116	12	308
Provision for depreciation	1	24	36	(1)	60
General taxes	6	9	7	—	22
Impairment of long-lived assets	—	292	—	—	292
Total operating expenses	1,609	763	265	(1,002)	1,635
OPERATING INCOME (LOSS)	(33)	(118)	116	(11)	(46)
OTHER INCOME (EXPENSE):					
Investment income	1	—	29	—	30
Miscellaneous income, including net income from equity investees	5	2	—	(4)	3
Interest expense — affiliates	—	(2)	—	—	(2)
Interest expense — other	(25)	(26)	(15)	16	(50)
Capitalized interest	—	19	4	—	23
Total other income (expense)	(19)	(7)	18	12	4
INCOME (LOSS) BEFORE INCOME TAXES	(52)	(125)	134	1	(42)
INCOME TAXES (BENEFITS)	(15)	(44)	52	2	(5)
NET INCOME (LOSS)	$(37)	$(81)	$82	$(1)	$(37)

Table of Contents

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Nine Months Ended September 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
REVENUES	$4,250	$1,794	$1,146	$(2,887)	$4,303
OPERATING EXPENSES:					
Fuel	26	911	125	—	1,062
Purchased power from affiliates	2,940	26	167	(2,887)	246
Purchased power from non-affiliates	1,206	—	—	—	1,206
Other operating expenses	218	290	372	36	916
Provision for depreciation	3	78	109	(4)	186
General taxes	18	32	21	—	71
Impairment of long-lived assets	—	294	—	—	294
Total operating expenses	4,411	1,631	794	(2,855)	3,981
OPERATING INCOME (LOSS)	(161)	163	352	(32)	322
OTHER INCOME (EXPENSE):					
Investment income	4	1	39	—	44
Miscellaneous income, including net income from equity investees	323	2	—	(315)	10
Interest expense to affiliates	—	(6)	(1)	—	(7)
Interest expense — other	(72)	(81)	(46)	48	(151)
Capitalized interest	1	55	11	—	67
Total other income (expense)	256	(29)	3	(267)	(37)
INCOME BEFORE INCOME TAXES	95	134	355	(299)	285
INCOME TAXES (BENEFITS)	(82)	52	130	8	108
NET INCOME	$177	$82	$225	$(307)	$177

Table of Contents

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of September 30, 2011	FES	FGCO	NGC	Eliminations		Consolidated
	(In millions)					
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$—	$6	$—	$—		$6
Receivables-						
Customers	452	—	—	—		452
Affiliated companies	438	504	234	(698	)	478
Other	22	21	18	—		61
Notes receivable from affiliated companies	262	921	2	(845	)	340
Materials and supplies, at average cost	58	224	195	—		477
Derivatives	170	—	—	—		170
Prepayments and other	49	12	—	—		61
	1,451	1,688	449	(1,543	)	2,045
PROPERTY, PLANT AND EQUIPMENT:						
In service	82	6,111	5,632	(385	)	11,440
Less — Accumulated provision for depreciation	17	2,097	2,379	(179	)	4,314
	65	4,014	3,253	(206	)	7,126
Construction work in progress	13	216	589	—		818
Property, plant and equipment held for sale, net	—	—	—	—		—
	78	4,230	3,842	(206	)	7,944
INVESTMENTS:						
Nuclear plant decommissioning trusts	—	—	1,187	—		1,187
Investment in affiliated companies	5,486	—	—	(5,486	)	—
Other	1	9	—	—		10
	5,487	9	1,187	(5,486	)	1,197
DEFERRED CHARGES AND OTHER ASSETS:						
Accumulated deferred income tax benefits	12	286	—	(298	)	—
Customer intangibles	126	—	—	—		126
Goodwill	24	—	—	—		24
Property taxes	—	16	25	—		41
Unamortized sale and leaseback costs	—	—	—	68		68
Derivatives	136	—	—	—		136
Other	39	102	10	(68	)	83
	337	404	35	(298	)	478
	$7,353	$6,331	$5,513	$(7,533	)	$11,664
LIABILITIES AND CAPITALIZATION						
CURRENT LIABILITIES:						
Currently payable long-term debt	$1	$385	$512	$(21	)	$877
Short-term borrowings-						
Affiliated companies	750	70	25	(845	)	—

Accounts payable-					
Affiliated companies	689	268	159	(691)	425
Other	80	90	—	—	170
Derivatives	175	—	—	—	175
Other	75	182	50	16	323
	1,770	995	746	(1,541)	1,970
CAPITALIZATION:					
Total equity	3,958	2,858	2,608	(5,466)	3,958
Long-term debt and other long-term obligations	1,484	1,942	706	(1,240)	2,892
	5,442	4,800	3,314	(6,706)	6,850
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	934	934
Accumulated deferred income taxes	—	—	523	(220)	303
Asset retirement obligations	—	27	862	—	889
Retirement benefits	51	248	—	—	299
Lease market valuation liability	—	183	—	—	183
Derivatives	67	—	—	—	67
Other	23	78	68	—	169
	141	536	1,453	714	2,844
	$7,353	$6,331	$5,513	$(7,533)	$11,664

Table of Contents

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$9	$—	$—	$9
Receivables-					
Customers	366	—	—	—	366
Affiliated companies	333	357	126	(338)	478
Other	21	56	13	—	90
Notes receivable from affiliated companies	34	189	174	—	397
Materials and supplies, at average cost	41	276	228	—	545
Derivatives	182	—	—	—	182
Prepayments and other	48	10	1	—	59
	1,025	897	542	(338)	2,126
PROPERTY, PLANT AND EQUIPMENT:					
In service	96	6,198	5,412	(385)	11,321
Less — Accumulated provision for depreciation	17	2,020	2,162	(175)	4,024
	79	4,178	3,250	(210)	7,297
Construction work in progress	9	520	534	—	1,063
	88	4,698	3,784	(210)	8,360
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,146	—	1,146
Investment in affiliated companies	4,942	—	—	(4,942)	—
Other	—	12	—	—	12
	4,942	12	1,146	(4,942)	1,158
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	43	412	—	(455)	—
Customer intangibles	134	—	—	—	134
Goodwill	24	—	—	—	24
Property taxes	—	16	25	—	41
Unamortized sale and leaseback costs	—	10	—	63	73
Derivatives	98	—	—	—	98
Other	21	71	14	(58)	48
	320	509	39	(450)	418
	$6,375	$6,116	$5,511	$(5,940)	$12,062
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$101	$419	$632	$(20)	$1,132
Short-term borrowings-					
Affiliated companies	—	12	—	—	12
Accounts payable-					

Affiliated companies	351	213	250	(347)	467
Other	139	102	—	—	241
Derivatives	266	—	—	—	266
Other	56	183	46	37	322
	913	929	928	(330)	2,440
CAPITALIZATION:					
Common stockholder's equity	3,788	2,515	2,414	(4,929)	3,788
Long-term debt and other long-term obligations	1,519	2,119	793	(1,250)	3,181
	5,307	4,634	3,207	(6,179)	6,969
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	959	959
Accumulated deferred income taxes	—	—	448	(390)	58
Asset retirement obligations	—	27	865	—	892
Retirement benefits	48	237	—	—	285
Lease market valuation liability	—	217	—	—	217
Derivatives	81	—	—	—	81
Other	26	72	63	—	161
	155	553	1,376	569	2,653
	$6,375	$6,116	$5,511	$(5,940)	$12,062

Table of Contents

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)	(322)	—	(473)
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
Customer acquisition costs	(2)	—	—	—	(2)
Other	(10)	(24)	—	—	(34)
Net cash provided from (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

Table of Contents

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Nine Months Ended September 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(289)	$402	$520	$(9)	$624
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	250	—	—	250
Redemptions and Repayments-					
Long-term debt	(1)	(261)	(43)	9	(296)
Other	(1)	—	—	—	(1)
Net cash used for financing activities	(2)	(11)	(43)	9	(47)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(417)	(379)	—	(801)
Proceeds from asset sales	—	117	—	—	117
Sales of investment securities held in trusts	—	—	1,478	—	1,478
Purchases of investment securities held in trusts	—	—	(1,511)	—	(1,511)
Loans to affiliated companies, net	406	(89)	(14)	—	303
Customer acquisition costs	(110)	—	—	—	(110)
Leasehold improvement payments to affiliated companies	—	—	(51)	—	(51)
Other	—	(2)	—	—	(2)
Net cash provided from (used for) investing activities	291	(391)	(477)	—	(577)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	—	—	—	—
Cash and cash equivalents at end of period	$—	$—	$—	$—	$—

Table of Contents

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

EXECUTIVE SUMMARY

Earnings Available to FirstEnergy Corp. in the third quarter of 2011 were $511 million, or basic and diluted earnings of $1.22 per share of common stock, compared with $179 million, or basic and diluted earnings of $0.59 per share of common stock in the third quarter of 2010. Earnings Available to FirstEnergy Corp. in the first nine months of 2011 were $742 million or basic earnings of $1.89 ($1.88 diluted) per share of common stock, compared with $599 million or basic earnings of $1.97 ($1.96 diluted) per share of common stock in the first nine months of 2010. 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 - 2010	$0.59	$1.97
Non-core asset sales/impairments	0.58	0.54
Trust securities impairments	(0.01)	0.01
Mark-to-market adjustments	0.02	—
Income tax charge from healthcare legislation - 2010	—	0.04
Regulatory charges	0.02	0.06
Litigation resolution	(0.01)	(0.07)
Merger-related costs	0.03	(0.27)
Segment operating results[(1)] -		
Regulated Distribution	0.02	0.02
Competitive Energy Services	0.13	(0.09)
Regulated Independent Transmission	(0.03)	(0.05)
Interest expense, net of amounts capitalized	(0.05)	(0.13)
Merger accounting — commodity contracts	(0.06)	(0.18)
Net merger accretion[(2)]	0.01	0.10
Settlement of uncertain tax positions	—	(0.05)
Other	(0.02)	(0.01)
Basic Earnings Per Share - 2011	$1.22	$1.89

(1) Excludes amounts that are shown separately

(2) Excludes merger accounting — commodity contracts, regulatory charges, mark-to-market adjustments and merger-related costs that are shown separately

Merger

On February 25, 2011, the merger between FirstEnergy and AE closed. Pursuant to the terms of the Agreement and Plan of Merger between FirstEnergy, Merger Sub and AE, Merger Sub merged with and into AE with AE continuing as the surviving corporation and a wholly owned subsidiary of FirstEnergy. As part of the merger, AE shareholders received 0.667 of a share of FirstEnergy common stock for each AE share outstanding as of the merger completion date and all outstanding AE equity-based employee compensation awards were converted into FirstEnergy equity-based awards on the same basis.

In connection with the merger, FirstEnergy recorded merger transaction costs of approximately $2 million ($1 million net of tax) and $14 million ($11 million net of tax) during the three months ended September 30, 2011 and 2010, respectively, and approximately $91 million ($73 million net of tax) and $35 million ($26 million net of tax) during the first nine months of 2011 and 2010, respectively. These costs are included in "Other operating expenses" in the Consolidated Statements of Income. FirstEnergy's consolidated financial statements include Allegheny's results of operations and financial position effective February 25, 2011. In addition, during the three months ended September 30, 2011, $3 million ($1 million net of tax) of merger integration costs and $2 million ($1 million net of tax) of charges from merger settlements approved by regulatory agencies were recognized. In the first nine months of

2011, $88 million ($67 million net of tax) of merger integration costs and $33 million ($20 million net of tax) of charges from merger settlements approved by regulatory agencies were recognized. Charges resulting from merger settlements are not expected to be

Table of Contents

material in future periods.
FirstEnergy expects to achieve its 2011 merger benefits target resulting from the merger with AE. Through September 2011, FirstEnergy has taken actions and completed savings initiatives that will allow the company to capture merger benefits of approximately $165 million pre-tax on an annual basis, or 79% of the $210 million annual target.

Operational Matters

Richland and Stryker Peaking Power Plants

On October 18, 2011, FirstEnergy closed on the sale of its Richland (432 MW) and Stryker (18 MW) Peaking Facilities for approximately $80 million. The proceeds from the sale of these non-core assets will be used to reduce FirstEnergy's net debt position.

Signal Peak

On October 18, 2011, FirstEnergy announced that Gunvor Group, Ltd. purchased a one-third interest in the Signal Peak coal mine in Montana. The sale strengthens FirstEnergy's balance sheet in the following ways:

- Proceeds of $257.5 million will be used to reduce FirstEnergy's net debt position
- De-consolidation of Signal Peak will result in the reduction of indebtedness by $360 million and an increase to equity of $50 million on FirstEnergy’s Consolidated Balance Sheet
- Estimated gain on sale and revaluation of remaining ownership stake will increase equity by an additional $370 million

Following the sale, FirstEnergy, through its wholly owned subsidiary, FEV, has a one-third interest in Global Mining Holding Company, LLC, a joint venture that owns Signal Peak. FGCO has revised its coal purchase agreement with Signal Peak to reduce delivery from up to 7.5 million tons annually to an obligation to accept up to 2 million tons each year.

FirstEnergy Utilities Respond to Hurricane Irene

In late August, 2011, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Irene. Approximately 1 million customers were affected by outages in areas served by its subsidiaries JCP&L, Met-Ed, Penelec and PE. Approximately 5,000 FirstEnergy employees and 1,000 contractors, including utility line workers from other utilities, assisted with the restoration work. The cost of the storm was approximately $78 million, of which $3 million reduced pre-tax income in the third quarter of 2011 and $75 million was capitalized or deferred for future recovery from customers.

Davis-Besse Outage

On October 1, 2011, the Davis-Besse Plant 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 replaces a head installed in 2002, enhances safety, reliability and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, a sub-surface hairline crack was identified in one of the exterior architectural elements on the Shield Building, following opening of the building for installation of the new reactor head. 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. The team of industry-recognized structural concrete experts and Davis-Besse engineers evaluating this condition has determined the cracking does not affect the facility's structural integrity or safety. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in two localized areas of the Shield Building similar to those found in the architectural elements. FENOC has determined these two areas are not associated with the architectural element cracking and are investigating them as a separate issue. FENOC's overall investigation and analysis continues. Davis-Besse is currently expected to return to service around the end of November.

Financial Matters

During the third quarter of 2011, FirstEnergy redeemed or repurchased approximately $425.8 million principal amount of PCRBs, as summarized in the following table. Approximately $28.5 million of FGCO FMBs and $98.9 million of NGC FMBs associated with such PCRBs were returned for cancellation by the associated LOC providers.

Table of Contents

Subsidiaries	Amount (In millions)	
AE Supply	$53.0	(a)
FGCO	$158.1	(b)
NGC	$158.9	(b)
MP	$70.2	(a)

(a) Includes $14.4 million in PCRBs redeemed for which MP and AE Supply are co-obligors.
(b) Subject to market conditions, these bonds are being held for future remarketing.

During the three months ended September 30, 2011, FirstEnergy received approximately $130 million from assigning a substantially below-market, long-term fossil fuel contract to a third party. As a result, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices. The new contract runs for nine years, which is the remaining term of the assigned contract. The transaction reduced fuel costs during the quarter by approximately $123 million.

FIRSTENERGY’S BUSINESS

With the completion of the Allegheny merger in the first quarter of 2011, FirstEnergy reorganized its management structure, which resulted in changes to its operating segments to be consistent with the manner in which management views the business. The new structure supports the combined company’s primary operations — distribution, transmission, generation and the marketing and sale of its products. The external segment reporting is consistent with the internal financial reporting used by FirstEnergy’s chief executive officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources. FirstEnergy now has three reportable operating segments — Regulated Distribution, Regulated Independent Transmission and Competitive Energy Services.

Prior to the change in composition of business segments, FirstEnergy’s business was comprised of two reportable operating segments. The Energy Delivery Services segment included FirstEnergy’s then eight existing utility operating companies that transmit and distribute electricity to customers and purchase power to serve their POLR and default service requirements. The Competitive Energy Services segment was comprised of FES, which supplies electric power to end-use customers through retail and wholesale arrangements. The “Other” amounts consisted of corporate items and other businesses that were below the quantifiable threshold for separate disclosure. Disclosures for FirstEnergy’s operating segments for 2010 have been reclassified to conform to the current presentation.

The changes in FirstEnergy’s reportable segments during the first quarter of 2011 consisted primarily of the following:

- Energy Delivery Services was renamed Regulated Distribution and the operations of MP, PE and WP, which were acquired as part of the merger with AE, and certain regulatory asset recovery mechanisms formerly included in the “Other” segment, were placed into this segment.
- A new Regulated Independent Transmission segment was created consisting of ATSI, and the operations of TrAIL and FirstEnergy’s interest in PATH; TrAIL and PATH were acquired as part of the merger with AE. The transmission assets and operations of JCP&L, Met-Ed, Penelec, MP, PE and WP remained within the Regulated Distribution segment.
- AE Supply, an operator of generation facilities that was acquired as part of the merger with AE, was placed into the Competitive Energy Services segment.

Financial information for each of FirstEnergy’s reportable segments is presented in the table below, which includes financial results for the Allegheny subsidiaries beginning February 25, 2011. FES and the Utility Registrants 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 67,000 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 the transmission operations of JCP&L, Met-Ed, Penelec, WP, MP and PE and the regulated electric generation facilities in West Virginia and New Jersey which MP and JCP&L, respectively, own or contractually control.

The Regulated Distribution segment's revenues are primarily derived from the delivery of electricity within FirstEnergy's service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (POLR, SOS or default service) in its Maryland, New Jersey, Ohio and Pennsylvania franchise areas. Its results reflect the commodity costs of securing electric generation from FES and AE Supply and from non-affiliated power suppliers and the deferral and amortization of certain fuel costs.
The Regulated Independent Transmission segment transmits electricity through transmission lines. Its revenues are primarily derived from the formula rate recovery of costs and a return on investment for capital expenditures in connection with TrAIL, PATH and other projects and revenues from providing transmission services to electric energy providers, power marketers and receiving

Table of Contents

transmission-related revenues from operating a portion of the FirstEnergy transmission system. Its results reflect the net PJM and MISO transmission expenses related to the delivery of the respective generation loads. On June 1, 2011, the ATSI transmission assets previously dedicated to MISO were integrated into the PJM market. All of FirstEnergy's assets now reside in one RTO.

The Competitive Energy Services segment, through FES and AE Supply, supplies electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements of FirstEnergy's Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. FES purchases the entire output of the 18 generating facilities which it owns and operates through its FGCO subsidiary (fossil and hydroelectric generating facilities) and owns, through its NGC subsidiary, FirstEnergy's nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, operates and maintains NGC's nuclear generating facilities 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 with non-affiliates, pursuant to full output, cost-of-service PSAs. AE Supply together with its consolidated subsidiary, AGC owns, operates and controls the electric generation capacity of 18 facilities. AGC owns and sells generation capacity to AE Supply and MP, which own approximately 59% and 41% of AGC, respectively. AGC's sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. All of AGC's revenues are derived from sales of its 1,109 MW share of generation capacity from the Bath County generation facility to AE Supply and MP.

This business segment controls approximately 20,000 MWs of capacity and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from affiliated and non-affiliated 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.

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.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. Results from the pre-merged companies have been segregated from the Allegheny companies for variance reporting and analysis. A reconciliation of segment financial results is provided in Note 14 to the consolidated financial statements. Earnings available to FirstEnergy by business segment were as follows:

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
	(In millions, except per share data)					
Earnings (Loss) By Business Segment:						
Regulated Distribution	$288	$202	$86	$568	$437	$131
Competitive Energy Services	232	(26)	258	249	164	85
Regulated Independent Transmission	34	22	12	78	45	33
Other and reconciling adjustments*	(43)	(19)	(24)	(153)	(47)	(106)
Earnings available to FirstEnergy Corp.	$511	$179	$332	$742	$599	$143
Basic Earnings Per Share	$1.22	$0.59	$0.63	$1.89	$1.97	$(0.08)
Diluted Earnings Per Share	$1.22	$0.59	$0.63	$1.88	$1.96	$(0.08)

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

Table of Contents

Summary of Results of Operations — Third Quarter 2011 Compared with Third Quarter 2010

Financial results for FirstEnergy's business segments in the third quarter of 2011 and 2010 were as follows:

Third Quarter 2011 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,809	$1,611	$—	$—	$4,420
Other	125	103	106	(48)	286
Internal	1	315	—	(303)	13
Total Revenues	2,935	2,029	106	(351)	4,719
Operating Expenses:					
Fuel	92	540	—	—	632
Purchased power	1,293	362	—	(306)	1,349
Other operating expenses	498	540	15	(29)	1,024
Provision for depreciation	159	110	17	6	292
Amortization of regulatory assets	123	—	(1)	—	122
General taxes	200	55	9	5	269
Impairment of long-lived assets	—	9	—	—	9
Total Operating Expenses	2,365	1,616	40	(324)	3,697
Operating Income	570	413	66	(27)	1,022
Other Income (Expense):					
Investment income	32	28	—	(12)	48
Interest expense	(147)	(82)	(13)	(25)	(267)
Capitalized interest	3	9	1	4	17
Total Other Expense	(112)	(45)	(12)	(33)	(202)
Income Before Income Taxes	458	368	54	(60)	820
Income taxes	170	136	20	(15)	311
Net Income (Loss)	288	232	34	(45)	509
Loss attributable to noncontrolling interest	—	—	—	(2)	(2)
Earnings Available to FirstEnergy Corp.	$288	$232	$34	$(43)	$511

Table of Contents

Third Quarter 2010 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,609	$940	$—	$—	$3,549
Other	76	62	73	(32)	179
Internal	60	599	—	(659)	—
Total Revenues	2,745	1,601	73	(691)	3,728
Operating Expenses:					
Fuel	—	400	—	—	400
Purchased power	1,473	505	—	(659)	1,319
Other operating expenses	400	345	15	(22)	738
Provision for depreciation	102	67	9	4	182
Amortization of regulatory assets	176	—	—	—	176
General taxes	167	28	8	3	206
Impairment of long-lived assets	—	292	—	—	292
Total Operating Expenses	2,318	1,637	32	(674)	3,313
Operating Income	427	(36)	41	(17)	415
Other Income (Expense):					
Investment income	24	27	—	(5)	46
Interest expense	(125)	(56)	(6)	(21)	(208)
Capitalized interest	—	23	—	18	41
Total Other Expense	(101)	(6)	(6)	(8)	(121)
Income Before Income Taxes	326	(42)	35	(25)	294
Income taxes	124	(16)	13	(2)	119
Net Income (Loss)	202	(26)	22	(23)	175
Loss attributable to noncontrolling interest	—	—	—	(4)	(4)
Earnings Available to FirstEnergy Corp.	$202	$(26)	$22	$(19)	$179

Table of Contents

Changes Between Third Quarter 2011 and Third Quarter 2010 Financial Results Increase (Decrease)	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$200	$671	$—	$—	$871
Other	49	41	33	(16)	107
Internal	(59)	(284)	—	356	13
Total Revenues	190	428	33	340	991
Operating Expenses:					
Fuel	92	140	—	—	232
Purchased power	(180)	(143)	—	353	30
Other operating expenses	98	195	—	(7)	286
Provision for depreciation	57	43	8	2	110
Amortization of regulatory assets	(53)	—	(1)	—	(54)
General taxes	33	27	1	2	63
Impairment of long-lived assets	—	(283)	—	—	(283)
Total Operating Expenses	47	(21)	8	350	384
Operating Income	143	449	25	(10)	607
Other Income (Expense):					
Investment income	8	1	—	(7)	2
Interest expense	(22)	(26)	(7)	(4)	(59)
Capitalized interest	3	(14)	1	(14)	(24)
Total Other Expense	(11)	(39)	(6)	(25)	(81)
Income Before Income Taxes	132	410	19	(35)	526
Income taxes	46	152	7	(13)	192
Net Income	86	258	12	(22)	334
Loss attributable to noncontrolling interest	—	—	—	2	2
Earnings Available to FirstEnergy Corp.	$86	$258	$12	$(24)	$332

Regulated Distribution — Third Quarter 2011 Compared with Third Quarter 2010

Net income increased by $86 million in the third quarter of 2011 compared to the third quarter of 2010, primarily due to earnings from the Allegheny companies and increased operating margins from the pre-merger companies (FirstEnergy excluding the Allegheny Companies) as a result of reduced purchased power costs, partially offset by reduced revenues.

Revenues —

The increase in total revenues resulted from the following sources:

Table of Contents

Revenues by Type of Service	Three Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
Pre-merger companies:			
Distribution services	$963	$1,041	$(78)
Generation sales:			
Retail	951	1,267	(316)
Wholesale	99	171	(72)
Total generation sales	1,050	1,438	(388)
Transmission	95	155	(60)
Other	59	111	(52)
Total pre-merger companies	2,167	2,745	(578)
Allegheny companies	768	-	768
Total Revenues	$2,935	$2,745	$190

The decrease in distribution service revenues for the pre-merger companies primarily reflects lower transition revenues due to the completion of transition cost recovery for CEI in December 2010, and an NJBPU-approved rate adjustment that became effective March 1, 2011, for all of JCP&L's customer classes, partially offset by increased rates associated with the recovery of deferred distribution costs and increased KWH deliveries. Distribution deliveries (excluding the Allegheny companies) increased by 2.1% in the third quarter of 2011 from the third quarter of 2010. The change in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	Three Months Ended September 30 2011	2010	Increase (Decrease)
	(in thousands)		
Pre-merger companies:			
Residential	11,443	11,342	0.9%
Commercial	8,967	9,034	(0.7)%
Industrial	9,532	8,954	6.4%
Other	128	130	(1.7)%
Total pre-merger companies	30,070	29,460	2.1%
Allegheny companies	10,580		
Total Electric Distribution KWH Deliveries	40,650	29,460	38.0%

Higher deliveries to residential customers reflected increased load growth slightly offset by lower weather-related usage in the third quarter of 2011. Lower deliveries to commercial customers reflected decreased weather-related usage compared to the same period in 2010. While cooling degree days were 29% above normal, they were 2% below 2010 levels. In the industrial sector, KWH deliveries increased to steel and electrical equipment customers by 9% and 11%, respectively, partially offset by decreased deliveries to automotive customers of 3%.

The following table summarizes the price and volume factors contributing to the $388 million decrease in generation revenues for the pre-merger companies in the third quarter of 2011 compared to the third quarter of 2010:

Table of Contents

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(451)
Change in prices	136
	(315)
Wholesale:	
Effect of decrease in sales volumes	(43)
Change in prices	(30)
	(73)
Net Decrease in Generation Revenues	$(388)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the service territories of the pre-merger companies in the third quarter of 2011, compared with the third quarter of 2010. Total generation provided by alternative suppliers as a percentage of total KWH deliveries increased to 78% from 64% for the Ohio Companies and to 54% from 10% for Met-Ed's, Penelec's and Penn's service areas.

The decrease in wholesale generation revenues reflected lower RPM revenues for Met-Ed and Penelec in the PJM market. Transmission revenues decreased $60 million primarily due to the termination of Met-Ed's and Penelec's TSC rates effective January 1, 2011. Transmission costs are now a component of the cost of generation established under Met-Ed's and Penelec's generation procurement plan.

The Allegheny companies added $768 million to revenues in the third quarter of 2011, including $184 million for distribution services, $519 million from generation sales and $65 million of transmission revenues.

Operating Expenses —

Total operating expenses increased by $47 million due to the following:

- Purchased power costs, excluding the Allegheny companies, were $529 million lower in the third quarter of 2011 due primarily to a decrease in volumes required. Decreased power purchased from FES reflected the increase in customer shopping described above and the termination of Met-Ed's and Penelec's partial requirements PSA with FES at the end of 2010. The increase in volumes purchased from non-affiliates under Met-Ed's and Penelec's generation procurement plan effective January 1, 2011 was offset by a decrease in RPM expenses in the PJM market. The Allegheny companies added $349 million in purchased power costs in the third quarter of 2011.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Pre-merger companies:	
Purchases from non-affiliates:	
Change due to decreased unit costs	$(226)
Change due to increased volumes	125
	(101)
Purchases from FES:	
Change due to increased unit costs	27
Change due to decreased volumes	(436)
	(409)
Increase in costs deferred	(19)
Total pre-merger companies	(529)
Purchases by Allegheny companies	349

Net Decrease in Purchased Power Costs	$(180)

95

Table of Contents

- Transmission expenses decreased $77 million primarily due to congestion costs for Met-Ed and Penelec in the third quarter of 2011. Met-Ed and Penelec defer or amortize the difference between revenues from their transmission rider and transmission costs incurred with no material effect on earnings.
- Energy Efficiency program costs, which are also recovered through rates, increased by $15 million.
- Hurricane Irene storm restoration maintenance expenses primarily impacting JCP&L and Met-Ed totaled $53 million in the third quarter of 2011, of which $50 million was deferred for future recovery from customers.
- Merger-related costs increased $3 million in the third quarter of 2011 compared to the same period of 2010.
- The inclusion of Allegheny Energy resulted in the following expenses in the third quarter of 2011:

Allegheny Expenses	In Millions
Purchased power	$349
Fuel	92
Transmission	38
Amortization of regulatory assets, net	(2)
Other	81
General taxes	39
Depreciation expense	48
Total Operating Expenses	$645

Other Expense —

Other expense increased $11 million in the third quarter of 2011 due to interest expense on debt of the Allegheny companies partially offset by higher investment income on OE's and TE's nuclear decommissioning trusts.

Regulated Independent Transmission — Third Quarter 2011 Compared with Third Quarter 2010

Net income increased by $12 million in the third quarter of 2011 compared to the third quarter of 2010 due to earnings associated with TrAIL and PATH of $26 million, partially offset by decreased earnings for ATSI of $14 million.

Revenues —

Total revenues increased by $33 million principally due to revenues from TrAIL and PATH, partially offset by a decrease in ATSI revenues due to the transition from MISO to PJM and the completion of vegetation management cost recovery in May 2011.

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

Revenues by Transmission Asset Owner	Three Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
ATSI	$49	$73	$(24)
TrAIL	53	—	53
PATH	4	—	4
Total Revenues	$106	$73	$33

Operating Expenses —

Total operating expenses increased by $8 million principally due to the addition of TrAIL and PATH in 2011.

Other Expense —

Other expense increased $6 million in the third quarter of 2011 due to additional interest expense associated with TrAIL.

Table of Contents

Competitive Energy Services — Third Quarter 2011 Compared with Third Quarter 2010

Net income increased by $258 million in the third quarter of 2011, compared to the third quarter of 2010, primarily due to last year's $292 million third quarter impairment charge ($181 million net of tax) related to operational changes at certain smaller coal-fired units. In addition, the current quarter experienced higher sales margins, partially offset by higher operation and maintenance expenses, non-core asset impairments and the effect of mark-to-market adjustments.

Revenues —

Total revenues increased by $428 million in the third quarter of 2011 primarily due to growth in direct and governmental aggregation sales and the inclusion of the Allegheny companies, partially offset by a decline in POLR and structured sales.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$1,071	$717	$354
POLR and Structured Sales	193	700	(507)
Wholesale	131	123	8
Transmission	30	22	8
RECs	12	—	12
Other	49	39	10
Allegheny Companies	543	—	543
Total Revenues	$2,029	$1,601	$428

Allegheny Companies	
Direct and Governmental Aggregation	$26
POLR and Structured Sales	165
Wholesale	330
Transmission	26
Other	(4)
Total Revenues	$543

MWH Sales by Type of Service	Three Months Ended September 30 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	12,675	7,817	62.1%
Governmental Aggregation	5,195	3,791	37.0%
POLR and Structured Sales	3,228	13,367	(75.9)%
Wholesale	1,334	1,743	(23.5)%
Allegheny Companies	8,930	—	—
Total Sales	31,362	26,718	17.4%

Allegheny Companies	
Direct	413
POLR	2,603
Structured Sales	179
Wholesale	5,735
Total Sales	8,930

97

Table of Contents

The increase in direct and governmental aggregation revenues of $354 million resulted from the acquisition of new commercial and industrial customers as well as new governmental aggregation contracts with communities in Ohio and Illinois that provided generation to approximately 1.7 million residential and small commercial customers at the end of September 2011 compared to approximately 1.2 million at the end of September 2010. Partially offsetting this increase, sales to residential and small commercial customers were adversely affected by weather that was 2% cooler this year in the markets served than in 2010.

The decrease in POLR and structured revenues of $507 million was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by higher unit prices to the Pennsylvania Companies. This decline in POLR and structured sales is the result of FES no longer having the responsibility to supply these default service requirements and is consistent with our business strategy to selectively participate in POLR auctions.

Wholesale revenues increased $8 million due to higher prices in the wholesale market, partially offset by reduced generation available for sale.

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 Sales:	
Effect of increase in sales volumes	$282
Change in prices	(22)
	260
Governmental Aggregation:	
Effect of increase in sales volumes	97
Change in prices	(3)
	94
Net Increase in Direct and Governmental Aggregation Revenues	$354

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
POLR:	
Effect of decrease in sales volumes	$(530)
Change in prices	23
	$(507)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(29)
Change in prices	37
	$8

Transmission revenues increased by $8 million primarily due to higher PJM congestion revenue. The revenues derived from the sale of RECs increased $12 million in the third quarter of 2011.

Operating Expenses —

Total operating expenses decreased by $21 million in the third quarter of 2011 due to the following:

- Purchased power costs, excluding the Allegheny companies, decreased $177 million as lower volumes ($237 million) were partially offset by higher unit prices ($60 million). The decrease in volume primarily relates to the absence in 2011 of a 1,300 MW third party contract associated with serving Met-Ed and Penelec that FES no longer has the requirement to

Table of Contents

serve.

- Fuel costs in the third quarter of 2011 were $129 million below the third quarter of 2010, principally reflecting cash received from assigning a substantially below-market, long-term fossil fuel contract to a third party. In connection with its merger integration initiatives and risk management strategy, FirstEnergy continues to evaluate opportunities with respect to its commodity contracts. As a result of the assignment, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices.
- Fossil operating costs increased by $6 million and nuclear operating costs by $16 million due primarily to higher labor, contractor and materials and equipment costs resulting from an increase in planned and unplanned outages.
- Transmission expenses increased $40 million due primarily to increases in PJM of $133 million from higher congestion, network and line loss costs, partially offset by lower MISO transmission expenses of $93 million due to lower congestion, network, and line loss costs.
- General taxes increased by $14 million due to an increase in revenue-related taxes.
- Depreciation expense increased $9 million due to property additions since the third quarter of 2010.
- Impairments of long-lived assets decreased $283 million principally due to an impairment charge of $292 million related to operational changes at certain smaller, coal-fired units that was recorded in the third quarter of 2010.
- Other operating expenses increased by $23 million primarily due to higher mark-to-market adjustments ($26 million).

The inclusion of the Allegheny companies' operations contributed $460 million to operating expenses, including a $7 million mark-to-market adjustment relating primarily to power contracts, as shown in the following table:

Source of Operating Expense (Credit)	
	(In millions)
Allegheny companies	
Fuel	$269
Purchased power	34
Fossil generation	36
Transmission	69
Mark-to-Market	(7)
General taxes	13
Other	12
Depreciation	34
Total Operating Expense	$460

Other Expense —

Total other expense in the third quarter of 2011 was $39 million higher than the third quarter of 2010, primarily due to an increase in net interest expense. The increase in interest expense was primarily due to the inclusion of the Allegheny companies ($23 million) and lower capitalized interest ($14 million) associated with the completion of the Sammis AQC project in 2010.

Other — Third Quarter of 2011 Compared with Third Quarter of 2010

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 $24 million decrease in earnings available to FirstEnergy in the third quarter of 2011 compared to the same period in 2010. The decrease resulted primarily from decreased capitalized interest ($14 million) resulting from completed construction projects and decreased investment income ($7 million).

Table of Contents

Summary of Results of Operations — First Nine Months of 2011 Compared with the First Nine Months of 2010

Financial results for FirstEnergy's business segments in the first nine months of 2011 and 2010 were as follows:

First Nine Months 2011 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$7,336	$4,167	$—	$—	$11,503
Other	351	283	278	(117)	795
Internal	1	976	—	(920)	57
Total Revenues	7,688	5,426	278	(1,037)	12,355
Operating Expenses:					
Fuel	189	1,531	—	—	1,720
Purchased power	3,616	1,062	—	(923)	3,755
Other operating expenses	1,322	1,807	51	(50)	3,130
Provision for depreciation	428	305	42	19	794
Amortization of regulatory assets	339	—	5	—	344
General taxes	556	150	25	17	748
Impairment of long-lived assets	—	30	—	11	41
Total Operating Expenses	6,450	4,885	123	(926)	10,532
Operating Income	1,238	541	155	(111)	1,823
Other Income (Expense):					
Investment income	84	49	—	(33)	100
Interest expense	(427)	(226)	(34)	(76)	(763)
Capitalized interest	7	31	2	15	55
Total Other Expense	(336)	(146)	(32)	(94)	(608)
Income Before Income Taxes	902	395	123	(205)	1,215
Income taxes	334	146	45	(35)	490
Net Income	568	249	78	(170)	725
Loss attributable to noncontrolling interest	—	—	—	(17)	(17)
Earnings Available to FirstEnergy Corp.	$568	$249	$78	$(153)	$742

Table of Contents

First Nine Months 2010 Financial Results	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$7,250	$2,348	$—	$—	$9,598
Other	233	170	189	(89)	503
Internal	79	1,812	—	(1,824)	67
Total Revenues	7,562	4,330	189	(1,913)	10,168
Operating Expenses:					
Fuel	—	1,084	—	—	1,084
Purchased power	4,159	1,285	—	(1,824)	3,620
Other operating expenses	1,090	1,037	45	(60)	2,112
Provision for depreciation	312	215	28	10	565
Amortization of regulatory assets	543	—	6	—	549
General taxes	459	92	22	14	587
Impairment of long-lived assets	—	294	—	—	294
Total Operating Expenses	6,563	4,007	101	(1,860)	8,811
Operating Income	999	323	88	(53)	1,357
Other Income (Expense):					
Investment income	78	41	—	(26)	93
Interest expense	(375)	(169)	(17)	(67)	(628)
Capitalized interest	2	70	1	49	122
Total Other Expense	(295)	(58)	(16)	(44)	(413)
Income Before Income Taxes	704	265	72	(97)	944
Income taxes	267	101	27	(31)	364
Net Income	437	164	45	(66)	580
Loss attributable to noncontrolling interest	—	—	—	(19)	(19)
Earnings Available to FirstEnergy Corp.	$437	$164	$45	$(47)	$599

101

Table of Contents

Changes Between First Nine Months 2011 and First Nine Months 2010 Financial Results Increase (Decrease)	Regulated Distribution	Competitive Energy Services	Regulated Independent Transmission	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$86	$1,819	$—	$—	$1,905
Other	118	113	89	(28)	292
Internal	(78)	(836)	—	904	(10)
Total Revenues	126	1,096	89	876	2,187
Operating Expenses:					
Fuel	189	447	—	—	636
Purchased power	(543)	(223)	—	901	135
Other operating expenses	232	770	6	10	1,018
Provision for depreciation	116	90	14	9	229
Amortization of regulatory assets	(204)	—	(1)	—	(205)
General taxes	97	58	3	3	161
Impairment of long-lived assets	—	(264)	—	11	(253)
Total Operating Expenses	(113)	878	22	934	1,721
Operating Income	239	218	67	(58)	466
Other Income (Expense):					
Investment income	6	8	—	(7)	7
Interest expense	(52)	(57)	(17)	(9)	(135)
Capitalized interest	5	(39)	1	(34)	(67)
Total Other Expense	(41)	(88)	(16)	(50)	(195)
Income Before Income Taxes	198	130	51	(108)	271
Income taxes	67	45	18	(4)	126
Net Income	131	85	33	(104)	145
Loss attributable to noncontrolling interest	—	—	—	2	2
Earnings Available to FirstEnergy Corp.	$131	$85	$33	$(106)	$143

Regulated Distribution — First Nine Months of 2011 Compared to First Nine Months of 2010

Net income increased by $131 million in the first nine months of 2011, compared to the first nine months of 2010, primarily due to the absence of a $35 million regulatory asset impairment recorded in 2010 and the earnings contribution of the Allegheny companies, partially offset by the absence of a favorable property tax settlement in 2010.

Revenues —

The increase in total revenues resulted from the following sources:

Table of Contents

Revenues by Type of Service	Nine Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
Pre-merger companies:			
Distribution services	$2,683	$2,774	$(91)
Generation sales:			
Retail	2,571	3,542	(971)
Wholesale	319	568	(249)
Total generation sales	2,890	4,110	(1,220)
Transmission	182	453	(271)
Other	180	225	(45)
Total pre-merger companies	5,935	7,562	(1,627)
Allegheny companies	1,753	-	1,753
Total Revenues	$7,688	$7,562	$126

The decrease in distribution service revenues for the pre-merger companies primarily reflects lower transition revenues due to the completion of transition cost recovery for CEI in December 2010, and an NJBPU-approved rate adjustment that became effective March 1, 2011 for all of JCP&L's customer classes, partially offset by increased rates associated with the recovery of deferred distribution costs and increased KWH deliveries. Distribution deliveries (excluding the Allegheny companies) increased by 1.2% in the first nine months of 2011 from the same period in 2010. The change in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	Nine Months Ended September 30 2011	2010	Increase (Decrease)
	(in thousands)		
Pre-merger companies:			
Residential	30,704	30,460	0.8 %
Commercial	24,822	25,108	(1.1)%
Industrial	27,172	26,151	3.9 %
Other	383	392	(2.3)%
Total pre-merger companies	83,081	82,111	1.2 %
Allegheny companies	23,648		
Total Electric Distribution KWH Deliveries	106,729	82,111	30.0 %

Higher deliveries to residential customers reflected increased load growth slightly offset by lower weather-related usage for the first nine months of 2011. Lower deliveries to commercial customers reflected decreased weather-related usage compared to the same period in 2010. While cooling degree days were 29% above normal, they were 7% below 2010 levels. Industrial deliveries increased by 11% to steel, 15% to electrical equipment, and 6% to chemical customers, partially offset by lower sales to automotive customers and paper manufacturing customers of 2% and 6%, respectively.

The following table summarizes the price and volume factors contributing to the $1,220 million decrease in generation revenues in the first nine months of 2011 compared to the same period of 2010:

Table of Contents

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(1,277)
Change in prices	306
	(971)
Wholesale:	
Effect of decrease in sales volumes	(54)
Change in prices	(195)
	(249)
Net Decrease in Generation Revenues	$(1,220)

The decrease in retail generation sales volume was due to increased customer shopping in the Ohio Companies', Met-Ed's and Penelec's service territories in the first nine months of 2011 compared to the same period in 2010. Total generation provided by alternative suppliers as a percentage of total KWH deliveries increased to 76% from 60% for the Ohio Companies and to 50% from 9% for Met-Ed's, Penelec's and Penn's service areas.

The decrease in wholesale generation revenues reflected lower RPM revenues for Met-Ed and Penelec in the PJM market. Transmission revenues decreased $271 million primarily due to the termination of Met-Ed's and Penelec's TSC rates effective January 1, 2011. Transmission costs are now a component of the cost of generation established under Met-Ed's and Penelec's generation procurement plan.

The Allegheny companies added $1,753 million of revenues for the first nine months of 2011, including $401 million for distribution services, $1,196 million from generation sales and $156 million of transmission revenues.

Operating Expenses —

Total operating expenses decreased by $113 million due to the following:

- Purchased power costs, excluding the Allegheny companies, were $1,371 million lower in the first nine months of 2011 due to a decrease in volumes required. The decrease in power purchased from FES reflected the increase in customer shopping described above and the termination of Met-Ed's and Penelec's partial requirements PSA with FES at the end of 2010. The increase in volumes purchased from non-affiliates under Met-Ed's and Penelec's generation procurement plan effective January 1, 2011 was offset by a decrease in RPM expenses in the PJM market. The Allegheny companies added $828 million to purchased power costs in the first nine months of 2011.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Pre-merger companies:	
Purchases from non-affiliates:	
Change due to decreased unit costs	$(591)
Change due to increased volumes	403
	(188)
Purchases from FES:	
Change due to increased unit costs	99
Change due to decreased volumes	(1,246)
	(1,147)
Increase in costs deferred	(36)
Total pre-merger companies	(1,371)
Purchases by Allegheny companies	828
Net Decrease in Purchased Power Costs	$(543)

104

Table of Contents

- Transmission expenses decreased $254 million primarily due to lower PJM network transmission expenses for Met-Ed and Penelec in the first nine months of 2011. Met-Ed and Penelec defer or amortize the difference between revenues from their transmission rider and transmission costs incurred with no material effect on earnings.
- Energy efficiency program costs, which are also recovered through rates, increased $77 million.
- The absence of a $7 million favorable JCP&L labor settlement that occurred in the second quarter of 2010 resulted in a comparative cost increase in 2011.
- Hurricane Irene storm restoration maintenance expenses primarily impacting JCP&L and Met-Ed totaled $53 million in the third quarter of 2011, of which $50 million was deferred for future recovery from customers.
- A provision for excess and obsolete material of $13 million was recognized in the first nine months of 2011 due to revised inventory practices adopted in conjunction with the Allegheny merger.
- Net amortization of regulatory assets decreased $189 million primarily due to reduced net PJM transmission cost and transition cost recovery and the absence of a $35 million regulatory asset impairment recognized in 2010 associated with the filing of the Ohio Companies' ESP on March 23, 2010, partially offset by increased energy efficiency cost recovery and future recovery for Hurricane Irene costs.
- Merger-related costs increased $56 million in the first nine months of 2011 compared to the same period of 2010.
- General taxes increased by $8 million primarily due to the absence of a favorable property tax settlement recognized in 2010.
- The inclusion of Allegheny Energy resulted in the following expenses in 2011:

Allegheny Expense	In Millions
Purchased power	$828
Fuel	189
Transmission	91
Amortization or regulatory assets, net	(15)
Other	199
General taxes	89
Depreciation expense	112
Total Operating Expenses	$1,493

Other Expense —

Other expense increased by $41 million in the first nine months of 2011 primarily due to interest expense on debt of the Allegheny companies and lower investment income on OE's and TE's nuclear decommissioning trusts.

Regulated Independent Transmission — First Nine Months 2011 Compared with First Nine Months 2010

Net income increased by $33 million in the first nine months of 2011 compared to the first nine months of 2010 due to earnings associated with TrAIL and PATH of $52 million, partially offset by decreased earnings for ATSI of $19 million.

Revenues —

Total revenues increased by $89 million principally due to revenues from TrAIL and PATH partially offset by a decrease in ATSI revenues primarily due to the transition from MISO to PJM and the completion of vegetation management cost recovery in May 2011.

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

Table of Contents

Revenues by Transmission Asset Owner	Nine Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
ATSI	$155	$189	$(34)
TrAIL	114	—	114
PATH	9	—	9
Total Revenues	$278	$189	$89

Operating Expenses —

Total operating expenses increased by $22 million principally due to TrAIL and PATH operating expenses.

Other Expense —

Other expense increased $16 million in the first nine months of 2011 due to interest expense associated with TrAIL.

Competitive Energy Services — First Nine Months of 2011 Compared to First Nine Months of 2010

Net income increased by $85 million in the first nine months of 2011, compared to the first nine months of 2010, primarily due to higher sales margins, that were partially offset by higher O&M expenses, an inventory reserve adjustment and the effect of mark-to-market adjustments. 2011 results were also impacted by the absence of a $292 million ($181 million net-of-tax) non-core impairment charge taken in the third quarter of 2010.

Revenues —

Total revenues increased $1,096 million in the first nine months of 2011 primarily due to growth in direct and governmental aggregation sales and the inclusion of the Allegheny companies, partially offset by a decline in POLR and structured sales.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
Direct and Governmental Aggregation	$2,836	$1,814	$1,022
POLR and Structured Sales	798	2,014	(1,216)
Wholesale	288	265	23
Transmission	86	58	28
RECs	55	67	(12)
Other	130	112	18
Allegheny Companies	1,233	—	1,233
Total Revenues	$5,426	$4,330	$1,096

Allegheny Companies	
Direct and Governmental Aggregation	$60
POLR and Structured Sales	419
Wholesale	687
Transmission	70
Other	(3)
Total Revenues	$1,233

Table of Contents

MWH Sales by Type of Service	Nine Months Ended September 30 2011	2010	Increase (Decrease)
	(In thousands)		
Direct	33,893	20,675	63.9 %
Governmental Aggregation	13,475	9,238	45.9 %
POLR and Structured Sales	12,789	38,711	(67.0)%
Wholesale	2,714	3,281	(17.3)%
Allegheny Companies	19,617		
Total Sales	82,488	71,905	14.7 %

Allegheny Companies	
Direct	983
POLR	5,584
Structured Sales	1,328
Wholesale	11,722
Total Sales	19,617

The increase in direct and governmental aggregation revenues of $1,022 million resulted from the acquisition of new commercial and industrial customers as well as new governmental aggregation contracts with communities in Ohio and Illinois that provided generation to approximately 1.7 million residential and small commercial customers at the end of September 2011 compared to approximately 1.2 million customers at the end of September 2010.

The decrease in POLR revenues of $1,216 million was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by increased sales to non-affiliates and higher unit prices to the Pennsylvania Companies. This decline in POLR and structured sales is the result of FES no longer having the responsibility to supply these default service requirements and is consistent with our business strategy to selectively participate in POLR auctions.

Wholesale revenues increased by $23 million due to higher wholesale prices partially offset by decreased volumes. The lower sales volumes were the result of decreased short-term (net hourly positions) transactions in MISO. Additional capacity revenues earned by units that moved to PJM were partially offset by losses on financially settled sales.

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 Sales:	
Effect of increase in sales volumes	$775
Change in prices	(41)
	734
Governmental Aggregation:	
Effect of increase in sales volumes	276
Change in prices	12
	288
Net Increase in Direct and Governmental Aggregation Revenues	$1,022

Table of Contents

Source of Change in POLR Revenues	Increase (Decrease) (In millions)
POLR:	
Effect of decrease in sales volumes	$(1,349)
Change in prices	133
	$(1,216)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(46)
Change in prices	69
	$23

Transmission revenues increased by $28 million due primarily to higher MISO and PJM congestion revenue. The revenues derived from the sale of RECs declined $12 million in the first nine months of 2011.

Operating Expenses —

Total operating expenses increased by $878 million in the first nine months of 2011 due to the following:

- Purchased power costs, excluding the Allegheny companies, decreased by $331 million due primarily to lower volumes purchased ($481 million) partially offset by higher unit costs ($150 million). The decrease in volume primarily relates to the absence in 2011 of a 1,300 MW third party contract associated with serving Met-Ed and Penelec that FES no longer has the requirement to serve.
- Fuel costs decreased by $142 million principally reflecting cash received from assigning a substantially below-market long-term fossil fuel contract to a third party. In connection with its merger integration initiatives and risk management strategy, FirstEnergy continues to evaluate opportunities with respect to its commodity contracts. As a result of the assignment, FirstEnergy entered into a new long-term contract with another supplier for replacement fuel based on current market prices. Fuel costs also reflect the impacts of decreased volumes ($54 million), partially offset by higher unit prices due to increased coal transportation costs and higher nuclear fuel unit prices following the refueling outages that occurred in 2010.
- Fossil operating costs increased by $25 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned outages.
- Nuclear operating costs increased by $64 million due primarily to having two refueling outages, Perry and Beaver Valley 2, occurring in 2011. While Davis-Besse had a refueling outage in 2010, the work performed was largely capital-related.
- Transmission expenses increased by $216 million primarily due to increases in PJM of $332 million from higher congestion, network, and line loss expense, partially offset by lower MISO transmission expenses of $116 million.
- General taxes increased by $30 million due to an increase in revenue-related taxes.
- Depreciation expense increased $13 million due to increased property additions primarily related to AQC projects.
- Impairments of long-lived assets decreased $264 million principally due an impairment charge of $292 million related to operational changes at certain smaller, coal-fired units that was recorded in the third quarter of 2010.
- Other expenses increased by $94 million primarily due to: a $54 million provision for excess and obsolete material relating to revised inventory practices adopted in connection with the Allegheny merger; a $19 million increase in mark-to-market adjustments; a $3 million increase in professional and contractor costs and a $15 million increase in intercompany billings. Intercompany billings increased due to merger-related costs, partially offset by lower intersegment billings for leasehold costs from the Ohio Companies.

The inclusion of the Allegheny companies' operations added $1,173 million to expenses, including a $36 million mark-to-market adjustment relating primarily to power contracts, as shown in the following table:

108

Table of Contents

Source of Operating Expense

	(In millions)
Allegheny Companies	
Fuel	$589
Purchased power	108
Fossil	118
Transmission	168
Mark-to-Market	36
General taxes	28
Other	49
Depreciation	77
Total Operating Expense	$1,173

Other Expense —
Total other expense in the first nine months of 2011 was $88 million higher than the first nine months of 2010, primarily due to a $96 million increase in net interest expense, partially offset by an increase in nuclear decommissioning trust investment income ($8 million). The increase in interest expense was primarily due to the inclusion of the Allegheny companies ($54 million) and lower capitalized interest ($39 million) associated with the completion of the Sammis AQC project in 2010.

Other — First Nine Months of 2011 Compared to First Nine Months of 2010
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 $106 million decrease in earnings available to FirstEnergy in the first nine months of 2011 compared to the same period in 2010. The decrease resulted primarily from increased operating expenses resulting from adverse litigation resolution ($29 million), decreased capitalized interest and increased depreciation expense resulting from completed construction projects placed into service ($43 million), decreased investment income ($7 million) and an asset impairment charge in the first quarter of 2011 ($11 million).

Regulatory Assets
Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides the balance of net regulatory assets by company as of September 30, 2011, and December 31, 2010, and changes during the nine months then ended:

Regulatory Assets	September 30, 2011	December 31, 2010	Increase (Decrease)	
	(In millions)			
OE	$343	$400	$(57	)
CEI	291	370	(79	)
TE	70	72	(2	)
JCP&L	461	513	(52	)
Met-Ed	372	296	76	
Penelec	264	163	101	
Other*	359	12	347	
Total	$2,160	$1,826	$334	

*2011 includes $350 million related to the Allegheny companies.

The following tables provide information about the composition of net regulatory assets as of September 30, 2011 and December 31, 2010 and the changes during the nine month period:

Table of Contents

Regulatory Assets by Source	September 30, 2011	December 31, 2010	Increase (Decrease)	Amount of Increase Attributable to AE
	(In millions)			
Regulatory transition costs	$883	$770	$113	$—
Customer receivables for future income taxes	513	326	187	165
Loss on reacquired debt	51	48	3	8
Employee postretirement benefits	9	16	(7)	—
Nuclear decommissioning and spent fuel disposal costs	(203)	(184)	(19)	—
Asset removal costs	(232)	(237)	5	26
Deferred transmission costs	313	184	129	87
Deferred generation costs	389	386	3	13
Deferred distribution costs	276	426	(150)	—
Other	161	91	70	51
Total	$2,160	$1,826	$334	$350

FirstEnergy had $377 million of net regulatory liabilities as of September 30, 2011, including $367 million of net regulatory liabilities attributable to Allegheny that are primarily related to asset removal costs.

Regulatory assets that do not earn a current return totaled approximately $496 million as of September 30, 2011, of which $126 million relates to purchase accounting fair value adjustments to corresponding liabilities that do not accrue interest.

Regulatory assets not earning a current return for Met-Ed and Penelec were $158 million and $139 million, respectively, and include certain regulatory transition costs and PJM transmission costs. The regulatory transition costs are expected to be recovered by 2020.

Regulatory assets not earning a current return for JCP&L were $80 million and include certain storm damage costs and pension and postretirement benefits that are expected to be recovered by 2021.

Regulatory assets not earning a current return for FirstEnergy’s other utility subsidiaries was $119 million and includes certain deferred generation and other costs that are expected to be recovered though 2026.

CAPITAL RESOURCES AND LIQUIDITY

As of September 30, 2011, FirstEnergy had $291 million of cash and cash equivalents available to fund investments, operations and capital expenditures. In addition to internal sources to fund liquidity and capital requirements for 2011 and beyond, FirstEnergy may 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 issuances of debt and/or equity securities.

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. 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.

A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy’s liquidity position and ability to fund its capital requirements. To mitigate risk, FirstEnergy’s business strategy stresses financial discipline and a strong focus on execution. Major elements include the expectation of: adequate cash from operations, opportunities for favorable long-term earnings growth in the competitive generation markets, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital spending program, adequately funded pension plan, minimal near-term maturities of existing long-term debt, commitment to a secure dividend and a successful merger integration.

As of September 30, 2011, FirstEnergy’s net deficit in working capital (current assets less current liabilities) was principally due to currently payable long-term debt, which, as of September 30, 2011, included the following (in millions):

Table of Contents

Currently Payable Long-term Debt	(In millions)
Met-Ed, Penelec, FGCO and NGC PCRBs supported by bank LOCs [1]	$632
AE Supply unsecured note	503
FirstEnergy Corp. unsecured note	250
FGCO and NGC unsecured PCRBs [1]	243
WP unsecured note	80
NGC collateralized lease obligation bonds	59
Sinking fund requirements	52
Other notes	21
	$1,840

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

Credit Facility Borrowings and Liquidity

FirstEnergy had no significant short-term borrowings as of September 30, 2011 and approximately $700 million as of December 31, 2010. FirstEnergy's available liquidity as of October 28, 2011, is summarized in the following table:

Company	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	June 2016	$2,000	$1,951
FES / AE Supply	Revolving	June 2016	2,500	2,485
TrAIL	Revolving	Jan. 2013	450	450
AGC	Revolving	Dec. 2013	50	—
		Subtotal	$5,000	$4,886
		Cash	—	834
		Total	$5,000	$5,720

(1) FirstEnergy Corp. and regulated subsidiary borrowers.

Revolving Credit Facilities

FirstEnergy and certain of its subsidiaries participate in two five-year syndicated revolving credit facilities with aggregate commitments of $4.5 billion (Facilities).

An aggregate amount of $2 billion is available to be borrowed under a syndicated revolving credit facility (FirstEnergy Facility), subject to separate borrowing sublimits for each borrower. The borrowers under the FirstEnergy Facility are FirstEnergy, CEI, Met-Ed, OE, Penn, TE, ATSI, JCP&L, MP, Penelec, PE and WP. An additional $2.5 billion is available to be borrowed by FES and AE Supply under a separate syndicated revolving credit facility (FES/AE Supply Facility).

Commitments under each of the Facilities will be available until June 17, 2016, 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 will mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended.

Borrowings under each of the Facilities are subject to acceleration upon the occurrence of events of default that each borrower considers usual and customary, including a cross-default for other indebtedness in excess of $100 million. Defaults by either FES or AE Supply or their respective subsidiaries under the FES/AE Supply Facility or other indebtedness generally will not cross-default to FirstEnergy under the FirstEnergy Facility.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of September 30, 2011:

Table of Contents

Borrower	Revolving Credit Facility Sub-Limit (In millions)	Regulatory and Other Short-Term Debt Limitations	
FirstEnergy	$2,000	—	(a)
FES	$1,500	—	(b)
AE Supply	$1,000	—	(b)
OE	$500	$500	
CEI	$500	$500	
TE	$500	$500	
JCP&L	$425	$411	(c)
Met-Ed	$300	$300	(c)
Penelec	$300	$300	(c)
West Penn	$200	$200	(c)
MP	$150	$150	(c)
PE	$150	$150	(c)
ATSI	$100	$100	
Penn	$50	$33	(c)

(a) No limitations.
(b) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
(c) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility and $700 million of the FirstEnergy 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.

Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2011, FirstEnergy's and its subsidiaries' debt to total capitalization ratios (as defined under each of the Facilities) were as follows:

Borrower		
FirstEnergy	55.1	%
FES	48.2	%
OE	54.7	%
Penn	36.1	%
CEI	55.8	%
TE	57.4	%
JCP&L	41.7	%
Met-Ed	52.5	%
Penelec	54.0	%
ATSI	54.3	%
MP	54.8	%
PE	57.1	%
WP	49.9	%
AE Supply	38.4	%

As of September 30, 2011, FirstEnergy could issue additional debt of approximately $9.1 billion, or recognize a reduction in equity of approximately $4.9 billion, and remain within the limitations of the financial covenants required by its credit facility.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances as a result of any change in credit ratings. Pricing is defined in “pricing grids,” whereby the cost of funds borrowed under the Facilities are related to the credit ratings of the company borrowing the funds.

Table of Contents

In addition to the Facilities, FirstEnergy also has established an additional $500 million of revolving credit facilities that are available to TrAIL ($450 million) and AGC ($50 million) until January 2013 and December 2013, respectively.

Under the terms of its 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. Outstanding debt for TrAIL may not exceed 65% of the sum of its debt and equity as of the last day of each calendar quarter through December 31, 2012. These provisions limit debt levels of these subsidiaries and also limit the net assets of each subsidiary that may be transferred to AE. As of September 30, 2011, the debt to total capitalization ratios for TrAIL and AGC (as defined under each of their credit facilities) were 38% and 50%, respectively.

As of September 30, 2011, TrAIL could issue additional debt of approximately $330 million, or recognize a reduction in equity of approximately $510 million and AGC could issue additional debt of approximately $40 million, or recognize a reduction in equity of approximately $70 million, and remain within the limitations of the financial covenants required by their credit facilities.

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 2011 was 0.47% per annum for the regulated companies’ money pool and 0.44% per annum for the unregulated companies’ money pool. FirstEnergy and its regulated companies acquired in the Allegheny merger have received the appropriate regulatory approvals to become part of the FirstEnergy regulated money pool.

Pollution Control Revenue Bonds

As of September 30, 2011, FirstEnergy’s currently payable long-term debt included approximately $632 million (FES — $558 million, Met-Ed — $29 million and Penelec — $45 million) 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 bank LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy's variable interest rate PCRBs were issued by the following banks as of September 30, 2011:

LOC Bank	Aggregate LOC Amount[1] (In millions)	LOC Termination Date	Reimbursements of LOC Draws Due
UBS	$272	April 2014	April 2014
CitiBank N.A.	165	June 2014	June 2014
Wachovia Bank	153	March 2014	March 2014
The Bank of Nova Scotia	49	April 2014	Multiple dates[2]
Total	$639		

(1) Includes approximately $7 million of applicable interest coverage.

(2) Shorter of 6 months or LOC termination date.

During the third quarter of 2011, FirstEnergy redeemed or repurchased approximately $425.8 million principal amount of PCRBs, as summarized in the following table. Approximately $28.5 million of FGCO FMBs and $98.9 million of NGC FMBs associated with such PCRBs were returned for cancellation by the associated LOC providers.

Subsidiaries	Amount (In millions)	
AE Supply	$53.0	(a)
FGCO	$158.1	(b)
NGC	$158.9	(b)
MP	$70.2	(a)

[a] Includes $14.4 million in PCRBs redeemed for which MP and AE Supply are co-obligors.
[b] Subject to market conditions, these bonds are being held for future remarketing.

Table of Contents

Long-Term Debt Capacity

As of September 30, 2011, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.6 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by the Ohio Companies is also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $115 million and $19 million, respectively. As a result of its indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $361 million and $352 million, respectively, under provisions of their senior note indentures as of September 30, 2011. In addition, based upon their respective FMB indentures, net earnings and available bondable property additions as of September 30, 2011, MP, PE and WP had the capability to issue approximately $1.3 billion of additional FMBs in the aggregate.

Based upon FGCO’s net earnings and available bondable property additions under its FMB indentures as of September 30, 2011, FGCO had the capability to issue $2.2 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, 2011, NGC had the capability to issue $1.9 billion of additional FMBs as of September 30, 2011 under the terms of that indenture. In connection with the third quarter 2011 PCRB repurchases, $28.5 million of FGCO and $98.9 million of NGC FMBs were returned by the associated LOC providers and canceled.

FirstEnergy’s access to capital markets and costs of financing are influenced by the ratings of its securities. On March 21, 2011, S&P affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries. On May 27, 2011, Fitch upgraded ratings for certain subsidiaries and revised the outlook to stable from negative for FirstEnergy and FES. On August 18, 2011, Moody's downgraded ratings for FES to Baa3 from Baa2 and revised FES' outlook to stable. The following table displays FirstEnergy’s and its subsidiaries’ securities ratings as of October 28, 2011.

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FirstEnergy Corp.	—	—	—	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+
Met-Ed	BBB	A3	A-	BBB-	Baa2	BBB+
MP	BBB+	Baa1	A-	BBB-	Baa3	BBB+
OE	BBB	A3	BBB+	BBB-	Baa2	BBB
Penelec	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+	—	—	—
PE	BBB+	Baa1	A-	BBB-	Baa3	BBB+
TE	BBB	Baa1	BBB	—	—	—
TrAIL	—	—	—	BBB-	Baa2	A-
WP	BBB+	A3	A-	BBB-	Baa2	BBB+

Changes in Cash Position

As of September 30, 2011, FirstEnergy had $291 million of cash and cash equivalents compared to approximately $1 billion as of December 31, 2010. As of September 30, 2011 and December 31, 2010, FirstEnergy had approximately $78 million and $13 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During the first nine months of 2011, FirstEnergy received $1.4 billion from cash dividends and equity repurchases by its subsidiaries and paid $651 million in cash dividends to common shareholders, including $20 million paid in March by AE to its former shareholders.

Cash Flows From Operating Activities

FirstEnergy’s consolidated net cash from operating activities is provided primarily by its regulated distribution, regulated independent transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating

Table of Contents

activities increased by $156 million during the first nine months of 2011 compared to the same period in 2010, as summarized in the following table:

Operating Cash Flows	Nine Months Ended September 30 2011	2010	Increase (Decrease)
	(In millions)		
Net income	$725	$580	$145
Non-cash charges	1,841	1,648	193
Pension trust contributions	(375)	—	(375)
Working capital and other	38	(155)	193
	$2,229	$2,073	$156

The increase in non-cash charges and other adjustments is primarily due to increased deferred taxes resulting from bonus depreciation ($377 million) and increased depreciation attributable to the acquired Allegheny companies ($229 million). These increases were partially offset by decreased asset impairments due to the impairment of certain FGCO facilities recorded in 2010 ($256 million) and lower amortization of regulatory assets from reduced net PJM transmission cost and transition cost recovery ($205 million).

The increase in cash flows from working capital and other is primarily due to decreased receivables from higher customer collections ($311 million) and decreased materials and supplies from the inventory valuation adjustment in the first quarter of 2011 ($68 million), partially offset by decreased payables ($138 million).

Cash Flows From Financing Activities

In the first nine months of 2011, cash used for financing activities was $2,402 million compared to $870 million in the comparable period of 2010. The following tables summarize new debt financing (net of any discounts) and redemptions:

Debt Issuances and Redemptions	Nine Months Ended September 30 2011	2010
	(In millions)	
New Issues		
PCRBs	$272	$250
Long-term revolving credit	70	—
Unsecured Notes	261	1
	$603	$251
Redemptions		
PCRBs	$738	$251
Long-term revolving credit	495	—
Senior secured notes	187	63
First mortgage bonds	14	7
Unsecured notes	147	101
	$1,581	$422
Short-term borrowings, net	$(700)	$(171)

Excluding PCRBs and sinking-fund requirements, issuances and redemptions during the third quarter of 2011 were are follows:

Date	Company	Type of Debt	Issued (Redeemed)

			(In millions)
July, 2011	AGC	Unsecured notes	$100
August, 2011	AGC	Unsecured notes	$(100)

115

Table of Contents

During the remainder of 2011 FirstEnergy and its subsidiaries may continue to pursue, from time to time, reductions in outstanding long-term debt through redemptions, open market or privately negotiated purchases. Any such transactions will be subject to prevailing market conditions, liquidity requirements, timing of asset sales and other factors.

Cash Flows From Investing Activities

Cash used for investing activities in the first nine months of 2011 resulted from cash used for property additions, partially offset by the cash acquired in the Allegheny merger and proceeds from asset sales. The following table summarizes investing activities for the first nine months of 2011 and the comparable period of 2010 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
	(In millions)			
Sources (Uses)				
Nine Months Ended September 30, 2011				
Regulated distribution	$(760)	$(3)	$(55)	$(818)
Competitive energy services	(608)	466	(30)	(172)
Regulated independent transmission	(105)	(1)	(1)	(107)
Cash received in Allegheny merger	—	590	—	590
Other and reconciling adjustments	(56)	(17)	25	(48)
Total	$(1,529)	$1,035	$(61)	$(555)
Nine Months Ended September 30, 2010				
Regulated distribution	$(499)	$82	$13	$(404)
Competitive energy services	(884)	(26)	(53)	(963)
Regulated independent transmission	(47)	—	(2)	(49)
Other and reconciling adjustments	(37)	(26)	34	(29)
Total	$(1,467)	$30	$(8)	$(1,445)

Net cash used in investing activities during the first nine months of 2011 decreased by $890 million compared to the same period of 2010. The decrease was principally due to cash acquired in the Allegheny merger ($590 million) and an increase in proceeds from asset sales ($402 million), partially offset by an increase in net purchases of investment securities ($90 million) and increased property additions ($62 million).

During last quarter of 2011, capital requirements for property additions and capital leases are estimated to be approximately $638 million, including approximately $35 million for nuclear fuel.

GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon either FirstEnergy or its subsidiaries' credit ratings.

As of September 30, 2011, FirstEnergy's maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $3.8 billion, as summarized below:

Table of Contents

Guarantees and Other Assurances	Maximum Exposure (In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$280
OVEC obligations	300
Other[2]	298
	878
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	154
FES' guarantee of NGC's nuclear property insurance	79
FES' guarantee of FGCO's sale and leaseback obligations	2,324
Other	16
	2,573
Surety Bonds	147
LOCs[3]	237
	384
Total Guarantees and Other Assurances	$3,835

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

(2) Includes guarantees of $95 million for nuclear decommissioning funding assurances, $161 million supporting OE's sale and leaseback arrangement, and $33 million for railcar leases.

(3) Includes $74 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $121 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE, $39 million pledged in connection with the sale and leaseback of Perry by OE and a $3 million LOC issued in connection with an AVE contractual obligation.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by its subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. FirstEnergy believes the likelihood is remote that such parental guarantees will increase amounts otherwise paid by FirstEnergy to meet its obligations incurred in connection with ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade to below investment grade, an acceleration or funding obligation or a "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of September 30, 2011, FirstEnergy's maximum exposure under these collateral provisions was $594 million, as shown below:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Credit rating downgrade to below investment grade [1]	$405	$7	$83	$495
Material adverse event [2]	32	56	11	99
Total	$437	$63	$94	$594

(1)

Includes $204 million and $53 million that is also considered an acceleration of payment or funding obligation for FES and the Utilities, respectively.

(2) Includes $29 million that is also considered an acceleration of payment or funding obligation for FES.

Stress case conditions of a credit rating downgrade or “material adverse event” and hypothetical increase in prices in the underlying commodity markets would increase the total potential amount to $662 million, as shown below:

Table of Contents

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Credit rating downgrade to below investment grade [1]	$466	$17	$83	$566
Material adverse event [2]	29	56	11	96
Total	$495	$73	$94	$662

(1) Includes $204 million and $53 million that is also considered an acceleration of payment or funding obligation for FES and the Utilities, respectively.

(2) Includes $29 million that is also considered an acceleration of payment or funding obligation for FES.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $147 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, contracts entered into by the Competitive Energy Services segment, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions that require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' and AE Supply's power portfolios as of September 30, 2011, and forward prices as of that date, FES and AE Supply have posted collateral of $123 million and $1 million, respectively. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one-year time horizon), FES and AE Supply would be required to post an additional $16 million and $1 million of collateral, respectively. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required to be posted.

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.

Signal Peak and Global Rail are borrowers under a $350 million syndicated two-year senior secured term loan facility due in October 2012. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership in the borrowers with FEV, have provided a guaranty of the borrowers' obligations under the facility. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the lenders under the term loan facility as collateral for the facility. On October 18, 2011, FEV sold a portion of its ownership interest in Signal Peak and Global Rail (see Note 15). Following the sale, FirstEnergy, WMB Loan Ventures LLC and WMB Loan Ventures II LLC will continue to guarantee the borrowers' obligations until either the facility is replaced with non-recourse financing no earlier than January 1, 2012, and no later than June 30, 2012, or replaced with appropriate recourse financing no earlier than September 4, 2012, that provides for separate guarantees from each owner in proportion with each equity owner's percentage ownership in the joint venture.

OFF-BALANCE SHEET ARRANGEMENTS

FES and 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 $1.6 billion as of September 30, 2011.

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. To manage the volatility relating to these exposures, FirstEnergy established a Risk Policy Committee, comprised of members of senior management, which provides general management oversight for risk management activities throughout FirstEnergy. The 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. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties.

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

Table of Contents

of fair value for financial reporting purposes and for internal management decision making (see Note 6 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of September 30, 2011 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2011	2012	2013	2014	2015	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$—	$—	$—	$—	$—	$—	$—
Other external sources[2]	(230)	(192)	(72)	(54)	—	—	(548)
Prices based on models	(3)	(5)	—	—	(1)	33	24
Total[3]	$(233)	$(197)	$(72)	$(54)	$(1)	$33	$(524)

(1) Represents exchange traded New York Mercantile Exchange futures and options.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

(3) Includes $487 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, 2011, an adverse 10% change in commodity prices would decrease net income by approximately $14 million during the next 12 months.

Equity Price Risk

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.

FirstEnergy provides a portion of non-contributory pre-retirement basic life insurance for employees who are eligible to retire. 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 also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. As of September 30, 2011, the FirstEnergy pension plan was invested in approximately 27% of equity securities, 50% of fixed income securities, 11% of absolute return strategies, 6% of real estate, 4% of private equity and 2% of 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 three and nine months ended September 30, 2011, FirstEnergy made pre-tax contributions to its qualified pension plans of $112 million and $375 million, respectively.

NDT funds have been established to satisfy NGC’s and the Utilities’ nuclear decommissioning obligations. As of September 30, 2011, approximately 19% of the funds were invested in fixed income securities, 9% of the funds were invested in equity securities and 72% 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 $393 million, $180 million and $1,493 million for fixed income securities, equity securities and short-term investments, respectively, as of September 30, 2011, excluding $22 million in a net liability position of receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $18 million reduction in fair value as of September 30, 2011. The decommissioning trusts of JCP&L and the Pennsylvania Companies are 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, OE and TE recognize in earnings the unrealized losses on available-for-sale securities held in their NDT as other-than-temporary impairments. 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 first nine months of 2011, approximately $1 million, $4 million and $1 million was contributed to the NDTs of JCP&L, OE and TE, respectively. FENOC has submitted a $95 million parental guarantee to the NRC for a short-fall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry.

CREDIT RISK

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. FirstEnergy engages in transactions for the purchase and sale of commodities including gas, electricity, coal and emission allowances. These transactions are often with major energy companies within the industry.

FirstEnergy maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FirstEnergy aggressively manages the quality of its portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of September 30, 2011, the largest credit concentration was with J.P. Morgan Chase & Co., which is currently rated investment grade, representing 11% of FirstEnergy's total approved credit risk comprised of 2% for FES, 2% for JCP&L, 2% for Met-Ed, 3% for WP and a combined 2% for the Ohio Companies.

OUTLOOK

RELIABILITY INITIATIVES

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FGCO, FENOC, ATSI and TrAIL. The NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by the RFC.

FirstEnergy believes that it generally 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, the 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. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to RFC a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, RFC issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to RFC on September 27, 2010. On July 8, 2011, RFC and Met-Ed signed a settlement agreement to resolve all outstanding issues related to the vegetation encroachment event. The settlement calls for Met-Ed to pay a penalty of $650,000, and for FirstEnergy to perform certain mitigating actions. These mitigating actions include inspecting FirstEnergy's transmission system using LiDAR technology, and reporting the results of inspections, and any follow-up work, to RFC. FirstEnergy was performing the LiDAR work in response to certain other industry directives issued by NERC in 2010. NERC subsequently approved the settlement agreement and, on September 30, 2011, submitted the approved settlement to FERC for final approval. FERC approved the settlement agreement on October 28, 2011.

MARYLAND

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a five-year cycle (to begin in 2008) for the MDPSC to report to the legislature on the status of SOS. PE now conducts rolling auctions to procure the power supply necessary to serve its customer load pursuant to a plan approved by the MDPSC. However, the terms on which PE will provide SOS to residential customers after the settlement beyond 2012 will depend on developments with respect to SOS in Maryland between now and then, including but not limited to possible MDPSC decisions in the proceedings discussed below.

The MDPSC opened a new docket in August 2007 to consider matters relating to possible “managed portfolio” approaches to SOS and other matters. “Phase II” of the case addressed utility purchases or construction of generation, bidding for procurement of demand response resources and possible alternatives if the TrAIL and PATH projects were delayed or defeated. It is unclear when the MDPSC will issue its findings in this proceeding.
In September 2009, the MDPSC opened a new proceeding to receive and consider proposals for construction of new generation resources in Maryland. In December 2009, Governor Martin O'Malley filed a letter in this proceeding in which he characterized the electricity market in Maryland as a “failure” and urged the MDPSC to use its existing authority to order the construction of new generation in Maryland, vary the means used by utilities to procure generation and include more renewables in the generation mix. In August 2010, the MDPSC opened another new proceeding to solicit comments on the PJM RPM process. Public hearings on the comments were held in October 2010. In December 2010, the MDPSC issued an order soliciting comments on a model request

Table of Contents

for proposal for solicitation of long-term energy commitments by Maryland electric utilities. PE and numerous other parties filed comments, and on September 29, 2011, the MDPSC issued an order requiring the utilities to issue the RFP crafted by the MDPSC by October 7, 2011. The RFPs were issued by the utilities as ordered by the MDPSC. The order indicated that bids were due by November 11, 2011, that the MDPSC would be the entity evaluating all bids, and that a hearing on whether to require the purchase of generation in light of the bids would be held on January 31, 2012, after receipt of further comments from all interested parties on January 13, 2012.

In September 2007, the MDPSC issued an order that required the Maryland utilities to file detailed plans for how they will meet the “EmPOWER Maryland” proposal that electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals. In 2008, PE filed its comprehensive plans for attempting to achieve those goals, asking the MDPSC to approve programs for residential, commercial, industrial, and governmental customers, as well as a customer education program. The MDPSC ultimately approved the programs in August 2009 after certain modifications had been made as required by the MDPSC, and approved cost recovery for the programs in October 2009. Expenditures were estimated to be approximately $101 million and would be recovered over the following six years. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, PE's plans for additional and improved programs for the period 2012-2014 were filed on August 31, 2011. Hearings on those plans and the plans of the other utilities were held in mid October 2011.

In March 2009, the MDPSC issued an order temporarily suspending the right of all electric and gas utilities in the state to terminate service to residential customers for non-payment of bills. The MDPSC subsequently issued an order making various rule changes relating to terminations, payment plans, and customer deposits that make it more difficult for Maryland utilities to collect deposits or to terminate service for non-payment. The MDPSC is continuing to conduct hearings and collect data on payment plan and related issues and has adopted regulations that expand the summer and winter “severe weather” termination moratoria when temperatures are very high or very low, from one day, as provided by statute, to three days on each occurrence.

On March 24, 2011, the MDPSC held an initial hearing to discuss possible new regulations relating to service interruptions, storm response, call center metrics, and related reliability standards. The proposed rules included provisions for civil penalties for non-compliance. Numerous parties filed comments on the proposed rules and participated in the hearing, with many noting issues of cost and practicality relating to implementation. The Maryland legislature passed a bill on April 11, 2011, which requires the MDPSC to promulgate rules by July 1, 2012 that address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. In crafting the regulations, the legislation directs the MDPSC to 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 to assess each utility's compliance with the standards, and may assess penalties of up to $25,000 per day per violation. The MDPSC convened a working group of utilities, regulators, and other interested stakeholders to address the topics of the proposed rules. A draft of the rules was filed, along with the report of the working group, on October 27, 2011. Comments on the draft rules are due by November 16, and a hearing to consider the rules and comments is scheduled for December 8 and 9, 2011. Separately, on July 7, 2011, the MDPSC adopted draft rules requiring monitoring and inspections for contact voltage. The draft rules were published in September, and then approved by the MDPSC as final rules on October 31, 2011. The rules will go into effect after being published again in the Maryland Register.

NEW JERSEY

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 requests 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. JCP&L filed an answer to the Petition on September 28, 2011, stating, inter alia, that the Division of Rate Counsel analysis upon which it premises its Petition contains errors and inaccuracies, that JCP&L's achieved return on equity is currently within a reasonable range, and that there is no reason for the NJBPU to require JCP&L to file a base rate case at this time. The matter is pending before the NJBPU.

On September 22, 2011, the NJBPU ordered that JCP&L hire a Special Reliability Master, subject to NJBPU approval, to evaluate JCP&L's design, operating, maintenance and performance standards as they pertain to the Morristown, New Jersey underground electric distribution system, and make recommendations to JCP&L and the NJBPU on the appropriate courses of action necessary to ensure adequate reliability and safety in the Morristown underground network. A schedule for the completion of the Special Reliability Master's activities has not yet been established.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held on September 26 and 27, 2011, to solicit public comments regarding the state of preparedness and responsiveness of the local electric distribution companies prior to, during and after Hurricane Irene. By subsequent Notice issued September 28, 2011, additional hearings were held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 2011 related to this inquiry. The NJBPU has not indicated what additional action, if any, may be taken as a result of information obtained through this process.

Table of Contents

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 (initial auctions held on October 20, 2010 and January 25, 2011); a load cap of no less than 80%, 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, 2015 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.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required 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 the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The PUCO issued an Opinion and Order generally approving the Ohio Companies' 3-year plan, and the Companies are in the process of implementing those programs included in the Plan. OE fell short of its statutory 2010 energy efficiency and peak demand reduction benchmarks and therefore, on January 11, 2011, it requested that its 2010 energy efficiency and peak demand reduction benchmarks be amended to actual levels achieved in 2010. The PUCO granted this request on May 19, 2011 for OE, finding that the motion was moot for CEI and TE. Moreover, because the PUCO indicated, when approving the 2009 benchmark request, that it would modify the Ohio Companies' 2010 (and 2011 and 2012) energy efficiency benchmarks when addressing the portfolio plan, the Ohio Companies were not certain of their 2010 energy efficiency obligations. Therefore, CEI and TE (each of which achieved its 2010 energy efficiency and peak demand reduction statutory benchmarks) also requested an amendment if and only to the degree one was deemed necessary to bring them into compliance with their yet-to-be-defined modified benchmarks. On June 2, 2011, the Companies filed an application for rehearing to clarify the decision related to CEI and TE. On July 27, 2011, the PUCO denied that application for rehearing, but clarified that CEI and TE could apply for an amendment in the future for the 2010 benchmarks should it be necessary to do so. 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. In addition to approving the programs included in the plan, with only minor modifications, the PUCO authorized the Ohio Companies to recover all costs related to the original CFL program that the Ohio Companies had previously suspended at the request of the PUCO. Applications for Rehearing were filed on April 22, 2011, regarding portions of the PUCO's decision, including the method for calculating savings and certain changes made by the PUCO to specific programs. On September 7, 2011, the PUCO denied those applications for rehearing.

Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they served in 2009 and 0.50% of the KWH they served in 2010. 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 March 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market and reduced the Ohio Companies' aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies' 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. On April 15, 2011, the Ohio Companies filed an application seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio on the basis that an insufficient quantity of solar resources are available in the market but reflecting solar RECs that they have obtained and providing additional information regarding efforts to secure solar RECs. On August 3, 2011, the PUCO granted the Ohio Companies' force majeure request for 2010 and increased their 2011 benchmark by the amount of SRECs generated in Ohio that the Ohio Companies were short in 2010. On September 2, 2011, the Environmental Law and Policy Center and Nucor Steel Marion, Inc. filed applications for rehearing. The Ohio Companies filed their response on September 12, 2011. These applications for rehearing were denied by the PUCO on September 20, 2011, but as part of its Entry on Rehearing the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. Separately, one party has filed a request that the PUCO audit the cost of the Ohio Companies' compliance with the alternative energy requirements and the Ohio Companies' compliance with Ohio law. The PUCO has not ruled on this request.

In February 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. In March 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect in March 2010. In April 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season and

Table of Contents

charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect in May 2010 and the proceeding remains open. The hearing on the matter was held in February 2011. The PUCO modified and approved the Ohio Companies' application on May 25, 2011, ruling that the new credit be applied only to customers that heat with electricity and be phased out over an eight-year period and granting authority for the Ohio Companies to recover deferred costs and associated carrying charges. OCC filed an application for rehearing on June 24, 2011 and the Ohio Companies filed their responses on July 5, 2011. The PUCO did not act on the application for rehearing within 30 days; thus, the application for rehearing is considered denied by operation of law. No appeal of this matter was filed and the time period in which to do so has expired.

PENNSYLVANIA

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, directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. In March 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. The PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC's order, Met-Ed and Penelec filed plans to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges. Pursuant to the plan approved by the PPUC, Met-Ed and Penelec began to refund those amounts to customers in January 2011, and the refunds will continue over a 29 month period until the full amounts previously recovered for marginal transmission loses are refunded. In April 2010, Met-Ed and Penelec 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 Met-Ed's and Penelec's TSC riders. Met-Ed and Penelec filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court and also a complaint seeking relief in federal district court., which was subsequently amended. The PPUC filed a Motion to Dismiss Met-Ed's and Penelec's Amended Complaint on September 15, 2011. Met-Ed and Penelec filed a Responsive brief in Opposition to the PPUC's Motion to Dismiss on October 11, 2011. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million ($189 million for Met-Ed and $65 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

In each of May 2008, 2009 and 2010, the PPUC approved Met-Ed's and Penelec'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 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 Met-Ed's customers to provide for full recovery by December 31, 2010.

In February 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. In July 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC's Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn's June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

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, or 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. Act 129 also required utilities to file with the PPUC a SMIP.

The PPUC entered an Order in February 2010 giving final approval to all aspects of the EE&C Plans of Met-Ed, Penelec and Penn and the tariff rider became effective March 1, 2010. On February 18, 2011, the companies filed a petition to approve their First Amended EE&C Plans. On June 28, 2011, a hearing on the petition was held before an administrative law judge.

WP filed its original EE&C Plan in June 2009, which the PPUC approved, in large part, by Opinion and Order entered in October 2009. In September 2010, WP filed an amended EE&C Plan that is less reliant on smart meter deployment, which the PPUC approved in January 2011.

On August 9, 2011, WP filed a petition to approve its Second Amended EE&C Plan. The proposed Second Revised Plan includes measures and a new program and implementation strategies consistent with the successful EE&C programs of Met-Ed, Penelec and Penn that are designed to enable WP to achieve the post-2011 Act 129 EE&C requirements.

Met-Ed, Penelec, Penn and WP submitted a preliminary status report on July 15, 2011, in which they reported on their compliance with statutory May 31, 2011 energy efficiency benchmarks. Preliminary results indicate that Met-Ed, Penelec and Penn will achieve their 2011 benchmarks; however WP may not. Final reports on actual results must be filed with the PPUC no later than November 15, 2011.

Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC in August 2009. This plan proposed a 24-month assessment period in which Met-Ed, Penelec and Penn will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs of approximately $29.5 million, which Met-Ed, Penelec and Penn, in their plan, proposed to recover through an automatic adjustment clause. The PPUC approved the SMIP, as modified by the ALJ, in June 2010. Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC's Order regarding the future ability to include smart meter costs in base rates, which the PPUC granted in part by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard, they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

In August 2009, WP filed its original SMIP, which provided for extensive deployment of smart meter infrastructure with replacement of all of WP's approximately 725,000 meters by the end of 2014. In December 2009, WP filed a motion to reopen the evidentiary record to submit an alternative smart meter plan proposing, among other things, a less-rapid deployment of smart meters.

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 smart meter deployment and certain smart meter dependent aspects of the EE&C Plan. In October 2010, WP and Pennsylvania's OCA filed a Joint Petition for Settlement addressing WP's smart meter implementation plan with the PPUC. Under the terms of the proposed settlement, 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. The proposed settlement also contemplates that WP 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 currently anticipates filing its plan for full-scale deployment of smart meters in June 2012. Under the terms of the proposed settlement, 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. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file in June 2012, or in a future base distribution rate case. Following additional proceedings, on March 9, 2011, WP submitted an Amended Joint Petition for Settlement which restates the Joint Petition for Settlement filed in October 2010, adds the PPUC's Office of Trial Staff as a signatory party, and confirms the support or non-opposition of all parties to the settlement. One party retained the ability to challenge the recovery of amounts spent on WP's original smart meter implementation plan. A Joint Stipulation with the OSBA was also filed on March 9, 2011. The PPUC approved the Amended Joint Petition for Full Settlement by order entered June 30, 2011.

By Tentative Order entered in September 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market will be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions. Met-Ed, Penelec, Penn Power and WP submitted joint comments on June 3, 2011. FES also submitted comments on June 3, 2011. On June 8, 2011, the PPUC conducted an en banc hearing on these issues at which both the Pennsylvania Companies and FES participated and offered testimony. A technical conference was held on August 10, 2011, and teleconferences are scheduled through December 14, 2011, to explore intermediate steps that can be taken to promote the development of a competitive market. An en banc hearing will be held on November 10, 2011. An intermediate work plan will be presented in December 2011 and a long range plan will be presented in the first quarter of 2012.

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

Table of Contents

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 calls for comments to be submitted within forty-five days of its publication in the Pennsylvania Bulletin, with no provision for replies. The Order has not been published yet. If implemented these rules could require a significant change in the way FES, Met-Ed, Penelec, Penn and WP do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition.

WEST VIRGINIA

In 2009, the West Virginia Legislature enacted the Alternative and Renewable Energy Portfolio Act (Portfolio Act), which generally requires that a specified minimum percentage of electricity sold to retail customers in West Virginia by electric utilities each year be derived from alternative and renewable energy resources according to a predetermined schedule of increasing percentage targets, including ten percent by 2015, fifteen percent by 2020, and twenty-five percent by 2025. In November 2010, the WVPSC issued Rules Governing Alternative and Renewable Energy Portfolio Standard (RPS Rules), which became effective on January 4, 2011. Under the RPS Rules, on or before January 1, 2011, each electric utility subject to the provisions of this rule was required to prepare an alternative and renewable energy portfolio standard compliance plan and file an application with the WVPSC seeking approval of such plan. MP and PE filed their combined compliance plan in December 2010. A hearing was held at the WVPSC on June 13, 2011. An order was issued by the WVPSC in September 2011 which conditionally approved MP's and PE's compliance plan, contingent on the outcome of the resource credits case discussed below.

Additionally, in January 2011, MP and PE filed an application with the WVPSC seeking to certify three facilities as Qualified Energy Resource Facilities. The application was approved and the three facilities are capable of generating renewable credits which will assist the companies in meeting their combined requirements under the Portfolio Act. Further, in February 2011, MP and PE filed a petition with the WVPSC seeking an Order declaring that MP is entitled to all alternative and renewable energy resource credits associated with the electric energy, or energy and capacity, that MP is required to purchase pursuant to electric energy purchase agreements between MP and three non-utility electric generating facilities in WV. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, has participated in the case in opposition to the Petition. A hearing was held at the WVPSC on August 25 and 26, 2011. An order is expected by the end of 2011.

In September 2011, MP and PE filed with the WVPSC to recover costs associated with fuel and purchased power (the ENEC) in the amount of $32 million which represents an approximate 3% overall increase in such costs over the past two years, primarily attributable to rising coal prices. The requested increase is partly offset by $2.5 million of synergy savings directly resulting from the merger of FirstEnergy and AE, which closed in February 2011. Under a cost recovery clause established by the WVPSC in 2007, MP and PE customer bills are adjusted periodically to reflect upward or downward changes in the cost of fuel and purchased power. The utilities' most recent request to recover costs for fuel and purchased power was in September 2009. A hearing on this matter is scheduled for November 29 - 30, 2011.

FERC MATTERS

Rates for Transmission Service Between MISO and PJM

In November 2004, FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as SECA) during a 16-month transition period. In 2005, FERC set the SECA for hearing. The presiding ALJ issued an initial decision in August 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision was subject to review and approval by FERC. In May 2010, FERC issued an order denying pending rehearing requests and an Order on Initial Decision which reversed the presiding ALJ's rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. In July 2010, a petition for review of the order denying pending rehearing requests was filed at the U.S. Court of Appeals for the D.C. Circuit. In a subsequent compliance filing submitted to the FERC in August 2010, the Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy thereafter executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy's liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon settlements were approved by FERC in November 2010, and the respective payments made. The subsidiaries of Allegheny entered into nine settlements to fix their liability for SECA charges with various parties. All of the settlements were approved by FERC and the respective payments have been made for eight of the settlements. Payments due under the remaining settlement will be made as a part of the refund obligations of the Utilities that are under review by FERC as part of a compliance filing. Potential refund obligations of FirstEnergy and the Allegheny subsidiaries are not expected to be material. On September 30, 2011, the FERC issued an order denying all requests for rehearing of the May 2010 Order on Initial Decision, affirming that prior order in all respects.

PJM Transmission Rate

In April 2007, FERC issued an order (Opinion 494) finding that the PJM transmission owners' existing “license plate” or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On

Table of Contents

the issue of rates for new transmission facilities, FERC directed 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. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology, which is generally referred to as a “beneficiary pays” approach to allocating the cost of high voltage transmission facilities.

FERC's Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision in August 2009. The court affirmed FERC's ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on this finding, remanded the rate design issue to FERC.

In an order dated January 21, 2010, FERC set the matter for a “paper hearing”-- meaning that FERC called for parties to submit written comments pursuant to the schedule described in the order. FERC identified nine separate issues for comments and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM's filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain load serving entities in PJM bearing the majority of the costs. 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 commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state commissions supported continued socialization of these costs on a load ratio share basis. This matter is awaiting action by FERC.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone entered into 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.

On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM's tariffs. On April 1, 2011, the MISO Transmission Owners (including ATSI) filed proposed tariff language that describes the mechanics of collecting and administering MTEP costs from ATSI-zone ratepayers. From March 20, 2011 through April 1, 2011, FirstEnergy, PJM and the MISO submitted numerous filings for the purpose of effecting movement of the ATSI zone to PJM on June 1, 2011. These filings include amendments to the MISO's tariffs (to remove the ATSI zone), submission of load and generation interconnection agreements to reflect the move into PJM, and submission of changes to PJM's tariffs to support the move into PJM.

On May 31, 2011, FERC issued orders that address the proposed ATSI transmission rate, and certain parts of the MISO tariffs that reflect the mechanics of transmission cost allocation and collection. In its May 31, 2011 orders, FERC approved ATSI's proposal to move the ATSI formula rate into the PJM tariff without significant change. Speaking to ATSI's proposed treatment of the MISO's exit fees and charges for transmission costs that were allocated to the ATSI zone, FERC required ATSI to present a cost-benefit study that demonstrates that the benefits of the move for transmission customers exceed the costs of any such move, which FERC had not previously required. Accordingly, FERC ruled that these costs must be removed from ATSI's proposed transmission rates until such time as ATSI files and FERC approves the cost-benefit study. On June 30, 2011, ATSI submitted the compliance filing that removed the MISO exit fees and transmission cost allocation charges from ATSI's proposed transmission rates. Also on June 30, 2011, ATSI requested rehearing of FERC's decision to require a cost-benefit study analysis as part of FERC's evaluation of ATSI's proposed transmission rates. Finally, and also on June 30, 2011, the MISO and the MISO TOs filed a competing compliance filing - one that would require ATSI to pay certain charges related to construction and operation of transmission projects within the MISO even though FERC ruled that ATSI cannot pass these costs on to ATSI's customers. ATSI on the one hand, and the MISO and MISO TOs on the other have, submitted subsequent filings - each of which is intended to refute the other's claims. ATSI's compliance filing and request for rehearing, as well as the pleadings that reflect the dispute between ATSI and the MISO/MISO TOs, are currently pending before FERC.

From late April 2011 through June 2011, FERC issued other orders that address ATSI's move into PJM. These orders approve ATSI's proposed interconnection agreements for large wholesale transmission customers and generators, and revisions to the PJM and MISO tariffs that reflect ATSI's move into PJM. In addition, FERC approved an “Exit Fee Agreement” that memorializes the agreement between ATSI and MISO with regard to ATSI's obligation to pay certain administrative charges to the MISO upon exit. Finally, ATSI and the MISO were able to negotiate an agreement of ATSI's responsibility for certain charges associated with long term firm transmission rights - that, according to the MISO, were payable by the ATSI zone upon its departure from the MISO. ATSI did not and does not agree that these costs should be charged to ATSI but, in order to settle the case and all claims associated with the case, ATSI agreed to a one-time payment of $1.8 million to the MISO. This settlement agreement has been submitted for FERC's review and approval. The final outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners jointly filed with FERC their proposed cost allocation methodology for certain new transmission projects. The new transmission projects--described as MVPs - are a class of transmission projects that

Table of Contents

are approved via MISO's formal transmission planning process (the MTEP). The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be "wheeled through" the MISO as well as to energy transactions that "source" in the MISO but "sink" outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO's Board approved the first MVP project -- the "Michigan Thumb Project." Under MISO's proposal, the costs of MVP projects 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 FirstEnergy. MISO estimated that approximately $15 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

In September 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO's proposal to allocate costs of MVPs projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the "beneficiary pays" approach). FirstEnergy also argued that, in light of progress that had been made to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO's MVP proposal.

In December 2010, FERC issued an order approving the MVP proposal without significant change. FERC's order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO's tariffs obligate ATSI to pay all charges that attached prior to ATSI's exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC's order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy requested rehearing of FERC's order. In its rehearing request, FirstEnergy argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. On October 21, 2011, FERC issued its order on rehearing. In the order, FERC noted that if liability for MVP costs were attached to ATSI prior to ATSI's exit, then ATSI would be responsible to pay the MVP charges. However, FERC did not address the question of whether liability for MVP costs should attach to ATSI. FirstEnergy is evaluating FERC's October 21, 2011 order, and continues to assess its future course of action.

As noted above, on February 1, 2011, ATSI filed proposed transmission rates related to its move into PJM. The proposed rates included line items that were intended to recover all MVP costs (if any) that might be charged to ATSI or to the ATSI zone. In its May 31, 2011 order on ATSI's proposed transmission rate FERC ruled that ATSI must submit a cost-benefit study before ATSI can recover the MVP costs. FERC further directed that ATSI remove the line-items from ATSI's formula rate that would recover the MVP costs until such time as ATSI submits and FERC approves the cost-benefit study. ATSI requested a rehearing of these parts of FERC's order and, pending this further legal process, has removed the MVP line items from its transmission rates.

On August 3, 2011, FirstEnergy filed a complaint with FERC based on the FERC's December 20, 2010, ruling. In the complaint, FirstEnergy argued that ATSI perfected the legal and financial requirements necessary to exit MISO before any MVP responsibilities could attach and asked FERC to rule that MISO cannot charge ATSI for MVP costs. On September 2, 2011, MISO, its TOs and other parties, filed responsive pleadings. MISO and its TOs argued that liability to pay for a single MVP project (the Michigan Thumb Project) attached to ATSI, before ATSI was able to exit MISO, and argued that FERC should order ATSI to pay a pro rata amount of the Michigan Thumb Project costs. On September 19, 2011, ATSI filed an answer stating its view that there are no legal or factual bases to charge the Michigan Thumb Project costs to ATSI. The complaint, and all subsequent pleadings, are pending before FERC. The October 21, 2011, FERC Order referenced above did not mention ATSI's rehearing order in the MVP docket. On

October 31, 2011, FirstEnergy filed notice of its plans to appeal FERC's October 21, 2011, Order with the D.C. Circuit Court of Appeals.

FirstEnergy cannot predict the outcome of these proceedings at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the United States Court of Appeals for the Ninth Circuit in pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit has since remanded one of those proceedings to FERC, which arises out of claims previously filed with FERC by the California Attorney General on behalf of certain California parties against various sellers in the California wholesale power market, including AE Supply (the Lockyer case). AE Supply and several other sellers filed motions to dismiss the Lockyer case. In March 2010, the judge assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. On May 4, 2011, FERC affirmed the judge's ruling. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. The request for rehearing remains pending.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second complaint with FERC against various sellers, including AE Supply (the Brown case), again seeking refunds for trades in the California energy markets during

Table of Contents

2000 and 2001. The above-noted trades with CDWR are the basis for including AE Supply in this new complaint. AE Supply filed a motion to dismiss the Brown complaint that was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. That request for rehearing also remains pending. FirstEnergy cannot predict the outcome of either of the above matters.

PATH Transmission Project

The PATH Project is comprised of a 765 kV transmission line that was proposed to extend from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland.

PJM initially authorized construction of the PATH Project in June 2007. In December 2010, PJM advised that its 2011 Load Forecast Report included load projections that are different from previous forecasts and that may have an impact on the proposed in-service date for the PATH Project. As part of its 2011 RTEP, and in response to a January 19, 2011 directive by a Virginia Hearing Examiner, PJM conducted a series of analysis using the most current economic forecasts and demand response commitments, as well as potential new generation resources. Preliminary analysis revealed the expected reliability violations that necessitated the PATH Project had moved several years into the future. Based on those results, PJM announced on February 28, 2011 that its Board of Managers had decided to hold the PATH Project in abeyance in its 2011 RTEP and directed FirstEnergy and AEP, as the sponsoring transmission owners, to suspend current development efforts on the project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the need for the project as part of its continuing RTEP process. PJM stated that its action did not constitute a directive to FirstEnergy and AEP to cancel or abandon the PATH Project. PJM further stated that it will complete a more rigorous analysis of the PATH Project and other transmission requirements and its Board will review this comprehensive analysis as part of its consideration of the 2011 RTEP. On February 28, 2011, affiliates of FirstEnergy and AEP filed motions or notices to withdraw applications for authorization to construct the project that were pending before state commissions in West Virginia, Virginia and Maryland. Withdrawal was deemed effective upon filing the notice with the MDPSC. The WVPSC and VSCC have granted the motions to withdraw.

PATH, LLC submitted a filing to FERC to implement a formula rate tariff effective March 1, 2008. In a November 19, 2010 order (November 19 Order) addressing various matters relating to the formula rate, FERC set the project's base return on equity for hearing and reaffirmed its prior authorization of a return on CWIP, recovery of start-up costs and recovery of abandonment costs. In the order, FERC also granted a 1.5% return on equity incentive adder and a 0.5% return on equity adder for RTO participation. These adders will be applied to the base return on equity determined as a result of the hearing. The PATH Companies, Joint Intervenors, Joint Consumer Advocates and FERC staff have agreed to a four year moratorium. A settlement was reached, which reflects a base ROE of 10.4% (plus authorized adders) effective January 1, 2011. Accordingly, the revised ROE will be reflected in a revised Projected Transmission Revenue Requirement for 2011 with true-up occurring in 2013. The FirstEnergy portion of the refund for March 1, 2008 through December 31, 2010 is approximately $2 million (inclusive of interest). The refund amount was computed using a base ROE of 10.8% plus authorized adders. On October 7, 2011 PATH and six intervenors submitted to FERC an unopposed settlement agreement. Contemporaneous with this submission, PATH LLC and the six intervenors filed with the Chief Administrative Law Judge of FERC a joint motion for interim approval and authorization to implement the refund on an interim basis pending issuance of a FERC order acting on the settlement agreement. On October 12, 2011, the motion for interim approval and authorization to implement the refund was granted by the Chief Administrative Law Judge. FERC has not acted on the settlement agreement.

Seneca Pumped Storage Project Relicensing

The Seneca (Kinzua) 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 PAD in the license docket.

On November 30, 2010, the Seneca Nation of Indians filed its notice of intent to relicense and PAD documents necessary for them 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 11, 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 September 26, 2011, third parties submitted comments regarding the parties' respective “Revised Study Plan”

Table of Contents

documents. On September 26, 2011, FirstEnergy submitted comments regarding certain factual and legal matters asserted in the Seneca Nation's Revised Study Plan document. On October 7, 2011, FirstEnergy submitted further comments to refute certain factual and legal arguments that were advanced by the Seneca Nation in comments that were submitted on September 26, 2011. On October 11, 2011, FERC Staff issued letters that finalize the studies that are to be performed. FirstEnergy and the Seneca Nation each will perform the studies described in the October 11, 2011 Staff determination. The study process will run through approximately November of 2013.

FirstEnergy cannot predict the outcome of these proceedings at this time.

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-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

In July 2008, three complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania seeking damages based on coal-fired Bruce Mansfield Plant air emissions. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner,” one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint seeking certification as a class action with the eight named plaintiffs as the class representatives. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the 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 Met-Ed in 1999) and Met-Ed. 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. In September 2009, the Court granted Met-Ed's motion to dismiss New Jersey's and Connecticut's claims for injunctive relief against Met-Ed, but denied Met-Ed's motion to dismiss the claims for civil penalties. The parties dispute the scope of Met-Ed's indemnity obligation to and from Sithe Energy, and Met-Ed 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 Portland coal-fired plant based on “modifications” dating back to 1986. On March 31, 2011, the EPA proposed emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Plant based on an interstate pollution transport petition submitted by New Jersey under Section 126 of the CAA. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on “modifications” dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of Keystone, and Penelec, as former owner and operator of Shawville, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. (Mission) alleging that “modifications” at the coal-fired Homer City Plant occurred from 1988 to the present without preconstruction NSR permitting in violation of the CAA's PSD program. In May 2010, the EPA issued a second NOV to Mission, Penelec, NYSEG and others that have had an ownership interest in Homer City containing in all material respects allegations identical to those included in the June 2008 NOV. In January 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against Penelec based on alleged “modifications” at Homer City 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 January 2011, another complaint was filed against Penelec and the other entities described above in the U.S. District Court for the Western District of Pennsylvania seeking damages based on Homer City's air emissions as well as certification as a class action and to enjoin Homer City from operating except in a “safe, responsible, prudent and proper manner.” Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint, but, at this time, is unable to predict the outcome of this matter or estimate the loss or possible range of loss. In addition, the Commonwealth of Pennsylvania and the States of New Jersey and New York intervened and have filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. Mission is seeking indemnification from Penelec, the co-owner and operator of Homer City prior to its sale in 1999. On April 21, 2011, Penelec and all other defendants filed Motions to Dismiss all of the federal claims and the various state claims. Responsive and Reply briefs were filed on May 26, 2011 and June 17, 2011, respectively. On October 12 and 13, 2011, the Court dismissed all of the claims with prejudice, of the U.S. and the Commonwealth of Pennsylvania and the Sates of New Jersey and New York and all of the claims of the private parties, without prejudice to refile state law claims in state court, against all of the defendants, including Penelec.

Table of Contents

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 occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake Plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake Plant. 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. Also, in June 2011, FirstEnergy received an information request pursuant to section 114(a) of the CAA for certain operating, maintenance and planning information, among other information regarding these plants. FGCO intends to comply with the CAA, including the EPA's information requests 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 CAA and related requirements, including potential application of the NSR standards 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. AE has provided responsive information to this and a subsequent request but is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In May 2004, AE, AE Supply, MP and WP received a Notice of Intent to Sue Pursuant to CAA §7604 from the Attorneys General of New York, New Jersey and Connecticut and from the PA DEP, alleging that Allegheny performed major modifications in violation of the PSD provisions of the CAA at the following West Virginia coal-fired plants: Albright Unit 3; Fort Martin Units 1 and 2; Harrison Units 1, 2 and 3; Pleasants Units 1 and 2 and Willow Island Unit 2. The Notice also alleged PSD violations at the Armstrong, Hatfield's Ferry and Mitchell coal-fired plants in Pennsylvania and identifies PA DEP as the lead agency regarding those facilities. In September 2004, AE, AE Supply, MP and WP received a separate Notice of Intent to Sue from the Maryland Attorney General that essentially mirrored the previous Notice.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the United States District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the CAA and the Pennsylvania Air Pollution Control Act at the Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. A non-jury trial on liability only was held in September 2010. Plaintiffs filed their proposed findings of fact and conclusions of law in December 2010, Allegheny made its related filings in February 2011 and plaintiffs filed their responses in April 2011. The parties are awaiting a decision from the District Court, but there is no deadline for that decision and we are unable to predict the outcome or estimate the possible loss or range of loss.

In September 2007, Allegheny also 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 Hatfield's Ferry and Armstrong Plants in Pennsylvania and the Fort Martin and Willow Island coal-fired plants in West Virginia. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CAA matters described above but cannot predict their outcomes.

State Air Quality Compliance

In early 2006, Maryland passed the Healthy Air Act, which imposes state-wide emission caps on SO_2 and NOx, requires mercury emission reductions and mandates that Maryland join the RGGI and participate in that coalition's regional efforts to reduce CO_2 emissions. On April 20, 2007, Maryland became the 10th state to join the RGGI. The Healthy Air Act provides a conditional exemption for the R. Paul Smith coal-fired plant for NOx, SO_2 and mercury, based on a PJM declaration that the plant is vital to reliability in the Baltimore/Washington DC metropolitan area, which PJM determined in 2006. Pursuant to the legislation, the MDE passed alternate NOx and SO_2 limits for R. Paul Smith, which became effective in April 2009. However, R. Paul Smith is still required to meet the Healthy Air Act mercury reductions of 80% which began in 2010. The statutory exemption does not extend to R. Paul Smith's CO_2 emissions. Maryland issued final regulations to implement RGGI requirements in February 2008. Ten RGGI auctions have been held through the end of calendar year 2010. RGGI allowances are also readily available in the allowance markets, affording another mechanism by which to secure necessary allowances. On March 14, 2011, MDE requested PJM perform an analysis to determine if termination of operation at R. Paul Smith would adversely impact the reliability of electrical service in the PJM region under current system conditions. FirstEnergy is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2010, the WVDEP issued a NOV for opacity emissions at Allegheny's Pleasants coal-fired plant. In August 2011, Allegheny and WVDEP resolved the NOV through a Consent Order requiring installation of a reagent injection system to reduce opacity by September 2012.

National Ambient Air Quality Standards

Table of Contents

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 Circuit vacated CAIR “in its entirety” and directed the EPA to “redo its analysis from the ground up.” In December 2008, the Court reconsidered its prior ruling and 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 opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the “NOx SIP Call,” cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the “8-hour” ozone NAAQS. In July 2011, the EPA finalized the CSAPR to replace CAIR, which remains in effect until CSAPR becomes effective (60 days after publication in the Federal Register). CSAPR requires 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 October 6, 2011, EPA proposed to revise the certain state budgets (for Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas, and Wisconsin and new unit set-asides in Arkansas and Texas) and generating unit allocations (for Alabama, Indiana, Kansas, Kentucky, Ohio and Tennessee) for NOx and SO_2 emissions and proposed to delay restrictions on interstate trading of NOx and SO_2 emission allowances from 2012 to 2014. EPA's final CSAPR rule has been appealed to the U.S. Court of Appeals for the District of Columbia Circuit by various stakeholders, with several appellants seeking a stay of CSAPR pending its review by the Court. 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.

During the three months ended September 30, 2011, FirstEnergy recorded a pre-tax impairment charge of approximately $6 million ($1 million for FES and $5 million for AE Supply) for obsolete NOx emission allowances, including fair value adjustments in connection with the merger for AE Supply that can no longer be used after 2011. While the carrying value of FirstEnergy's SO_2 emission allowances are currently above market (currently reflected at $26 million on the Consolidated Balance Sheet as of September 30, 2011), Management determined that no impairment exists in the third quarter of 2011 since these allowances can be carried forward into future years. Management is continuing to assess the impact of CSAPR, other environmental proposals and other factors on FirstEnergy's competitive fossil generating facilities, including but not limited to, the impact on its SO_2 emission allowances and the continuing operations of its coal-fired plants.

Hazardous Air Pollutant Emissions

On March 16, 2011, the EPA released its MACT proposal to establish emission standards for mercury, hydrochloric acid and various metals for electric generating units. Final regulations are expected on or about December 16, 2011. Depending on the action taken by the EPA and how any future regulations are ultimately implemented, FirstEnergy's future cost of compliance with MACT regulations may be substantial and changes to FirstEnergy's operations may result.

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. The Senate continues to consider a number of measures to regulate GHG emissions. President Obama has announced his Administration's “New Energy for America Plan” that includes, among other provisions, proposals to ensure that 10% of electricity used in the United States comes from renewable sources by 2012, to increase to 25% by 2025, to implement an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. 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 GHG emissions commencing in 2010 and currently requires it to submit reports. 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 permits under the CAA's NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO_2) effective January 2, 2011 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 the next three years with a goal of increasing to $100 billion by 2020; and establishes the “Copenhagen 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,

Table of Contents

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.

In 2009, the U.S. Court of Appeals for the Second Circuit and the U.S. Court of Appeals for the Fifth Circuit reversed and remanded lower court decisions that had dismissed complaints alleging damage from GHG emissions on jurisdictional grounds. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. These cases involve common law tort claims, including public and private nuisance, alleging that GHG emissions contribute to global warming and result in property damages. The U.S. Supreme Court granted a writ of certiorari to review the decision of the Second Circuit. On June 20, 2011, the U.S. Supreme Court reversed the Second Circuit. The Court remanded to the Second Circuit the issue of whether the CAA preempted state common law nuisance actions. The Court's ruling also failed to answer the question of the extent to which actions for damages may remain viable.

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 Clean Water Act 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 Clean Water Act 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 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 Clean Water Act 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 Clean Water Act generally requiring fish impingement to be reduced to a 12% annual average and studies to be conducted at the majority of our existing generating facilities to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic life. On July 19, 2011, the EPA extended the public comment period for the new proposed Section 316(b) regulation by 30 days but stated its schedule for issuing a final rule remains July 27, 2012. 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. In November 2010, the Ohio EPA issued a permit for the coal-fired Bay Shore Plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. 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 Clean Water Act 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 August 5, 2011, EPA issued an information request pursuant to Sections 308 and 311 of the CWA for certain information pertaining to the oil spills and spill prevention measures at FirstEnergy facilities. FirstEnergy responded on October 10, 2011. On September 30, 2011, FirstEnergy executed tolling agreements with the EPA extending the

statute of limitations to April 30, 2012. FGCO does not anticipate any losses resulting from this matter to be material.
In May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash disposal site at the Albright coal-fired plant seeking unspecified civil penalties and injunctive relief. MP is currently seeking relief from the arsenic limits through WVDEP agency review. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served another 60-Day Notice of Intent required prior to filing a citizen suit under the Clean Water Act for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Station.
FirstEnergy intends to vigorously defend against the CWA matters described above but cannot predict their outcomes.
Monongahela River Water Quality
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 Hatfield's Ferry coal-fired plant. These

Table of Contents

criteria are reflected in the current PA DEP water discharge permit for that project. AE Supply appealed the PA DEP's permitting decision, which would require it to incur significant costs or negatively affect its ability to operate the scrubbers as designed. Preliminary studies indicate an initial capital investment in excess of $150 million in order to install technology to meet the TDS and sulfate limits in the permit. The permit has been independently appealed by Environmental Integrity Project and Citizens Coal Council, which seeks to impose more stringent technology-based effluent limitations. Those same parties have intervened in the appeal filed by AE Supply, and both appeals have been consolidated for discovery purposes. An order has been entered that stays the permit limits that AE Supply has challenged while the appeal is pending. A hearing on the parties' appeals was scheduled to begin in September 2011, however the Court stayed all prehearing deadlines on July 15, 2011 to allow the parties additional time to work out a settlement, and has rescheduled a hearing, if necessary, for July 2012. If these settlement discussions are successful, AE Supply anticipates that its obligations will not be material. AE Supply intends to vigorously pursue these issues, but cannot predict the outcome of these appeals.

In a parallel rulemaking, 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 only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

In December 2010, PA DEP submitted its Clean Water Act 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 its Hatfield's Ferry and Mitchell facilities in Pennsylvania and its Fort Martin facility in West Virginia.

In October 2009, the WVDEP issued the water discharge permit for the Fort Martin generation facility. Similar to the Hatfield's Ferry water discharge permit issued for the scrubber project, the Fort Martin permit imposes effluent limitations for TDS and sulfate concentrations. The permit also imposes temperature limitations and other effluent limits for heavy metals that are not contained in the Hatfield's Ferry water permit. Concurrent with the issuance of the Fort Martin permit, WVDEP also issued an administrative order that sets deadlines for MP to meet certain of the effluent limits that are effective immediately under the terms of the permit. MP appealed the Fort Martin permit and the administrative order. The appeal included a request to stay certain of the conditions of the permit and order while the appeal is pending, which was granted pending a final decision on appeal and subject to WVDEP moving to dissolve the stay. The appeals have been consolidated. MP moved to dismiss certain of the permit conditions for the failure of the WVDEP to submit those conditions for public review and comment during the permitting process. An agreed-upon order that suspends further action on this appeal, pending WVDEP's release for public review and comment on those conditions, was entered on August 11, 2010. The stay remains in effect during that process. The current terms of the Fort Martin permit would require MP to incur significant costs or negatively affect operations at Fort Martin. Preliminary information indicates an initial capital investment in excess of the capital investment that may be needed at Hatfield's Ferry in order to install technology to meet the TDS and sulfate limits in the Fort Martin permit, which technology may also meet certain of the other effluent limits in the permit. Additional technology may be needed to meet certain other limits in the permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals.

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 February 2009, the EPA requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous

waste.
In December 2009, in an advanced 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. 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 our results of operations and financial condition.
LBR CCB impoundment is expected to run out of disposal capacity for disposal of CCBs from the BMP between 2016 and 2018. In July 2011, BMP submitted a Phase I permit application to PA DEP for construction of a new dry CCB disposal facility adjacent to LBR. BMP anticipates submitting zoning applications for approval to allow construction of a new dry CCB disposal facility prior to commencing construction.
The Utility Registrants have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides

Table of Contents

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, 2011, based on estimates of the total costs of cleanup, the Utility Registrants' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $103 million (JCP&L - $69 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FirstEnergy - $31 million) have been accrued through September 30, 2011. Included in the total are accrued liabilities of approximately $63 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. On July 11, 2011, FirstEnergy was found to be a potentially responsible party under CERCLA indirectly liable for a portion of past and future clean-up costs at certain legacy MGP sites, estimated to total approximately $59 million. FirstEnergy recognized an additional expense of $29 million during the second quarter of 2011; $30 million had previously been reserved prior to 2011. FirstEnergy determined that it is reasonably possible that it or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses at those sites cannot be determined or reasonably estimated.

OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court's decision decertifying the class. In November 2010, the Supreme Court issued an order denying Plaintiffs' motion for leave to appeal. The Court's order effectively ends the attempt to certify the class, and leaves only nine (9) plaintiffs to pursue their respective individual claims. The matter was referred back to the lower court, which set a trial date for February 13, 2012 for the remaining individual plaintiffs. Plaintiffs have accepted an immaterial amount in final settlement of all matters and the settlement documentation is being finalized for execution by all parties.

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of September 30, 2011, 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. The NRC issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of nuclear facilities. On March 28, 2011, FENOC submitted its biennial report on nuclear decommissioning funding to the NRC. This submittal identified a total shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry of approximately $92.5 million. On June 24, 2011, FENOC submitted a $95 million parental guarantee to the NRC for its approval.

In January 2004, subsidiaries of FirstEnergy filed a lawsuit in the U.S. Court of Federal Claims seeking damages in connection with costs incurred at the Beaver Valley, Davis-Besse and Perry nuclear facilities as a result of the DOE's failure to begin accepting spent nuclear fuel on January 31, 1998. DOE was required to begin accepting spent nuclear fuel by the Nuclear Waste Policy Act (42 USC 10101 et seq) and the contracts entered into by the DOE and the owners and operators of these facilities pursuant to the Act. On January 18, 2011, the parties, FirstEnergy and DOJ, filed a joint status report that established a schedule for the litigation of these claims. FirstEnergy filed damages schedules and disclosures with the DOJ on February 11, 2011, seeking damages for delay costs incurred through September 30, 2010. The damage claim is subject to review and audit by DOE.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station 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. By this order, the ASLB also admitted two contentions challenging whether FENOC's Environmental Report adequately evaluated (1) a combination of renewable energy sources as alternatives to the renewal of Davis-Besse's operating license, and (2) severe accident mitigation alternatives at Davis-Besse. On May 6, 2011, FENOC filed an appeal with the NRC Commissioners from the order granting a hearing on the Davis-Besse license renewal application.
On April 14, 2011, a group of environmental organizations petitioned the NRC Commissioners to suspend certain pending nuclear licensing proceedings, including the Davis-Besse license renewal proceeding, to ensure that any safety and environmental implications of the accident at the Fukushima Daiichi Nuclear Power Station in Japan are considered. In a September 11, 2011 order, the NRC denied the request to suspend the licensing proceedings and referred to the NRC Task Force conducting a "Near-Term Evaluation of the Need for Agency Actions Following the Events in Japan" for those portions of the petitions requesting rulemaking.

On October 1, 2011, the Davis-Besse Plant was safely shut down for a scheduled outage to install a new reactor vessel head and

Table of Contents

complete other maintenance activities. The new reactor head, which replaces a head installed in 2002, enhances safety, reliability and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, a sub-surface hairline crack was identified in one of the exterior architectural elements on the Shield Building, following opening of the building for installation of the new reactor head. 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. The team of industry-recognized structural concrete experts and Davis-Besse engineers evaluating this condition has determined the cracking does not affect the facility's structural integrity or safety. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in two localized areas of the Shield Building similar to those found in the architectural elements. FENOC has determined these two areas are not associated with the architectural element cracking and are investigating them as a separate issue. FENOC's overall investigation and analysis continues. Davis-Besse is currently expected to return to service around the end of November.

By a 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 a supplemental 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.

On October 2, 2011, FENOC completed the controlled shutdown of the Perry plant due to the loss of a startup transformer. On October 11, 2011, FENOC submitted a Technical Specification change request to the NRC to clarify that a delayed access circuit is temporarily qualified for use as one of the required offsite power circuits. By a letter dated October 17, 2011, NRC authorized Perry to operate with a delayed access circuit for offsite power until December 12, 2011. Concurrently, a spare replacement transformer from Davis-Besse was transported to Perry for modification and installation.

In light of the impacts of the earthquake and tsunami on the reactors in Fukushima, Japan, the NRC conducted inspections of emergency equipment at US reactors. The NRC also established a Near-Term Task Force to review its processes and regulations in light of the incident, and, on July 12, 2011, the Task Force issued its report of recommendations for regulatory changes. On October 18, 2011, the NRC approved the Staff recommendations, and directed the Staff to implement its near-term recommendations without delay. Ultimately, the adoption of the Staff recommendations on near-term actions is likely to result in additional costs to implement plant modifications and upgrades required by the regulatory process over the next several years, which costs are likely to be material.

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). Post-trial filings occurred in May 2011, with Oral Argument on June 28, 2011. On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, ICG posted bond and filed a Notice of Appeal and a briefing schedule was issued with oral argument likely in May of 2012. AE Supply and MP intend to vigorously pursue this matter through appeal if necessary but cannot predict its outcome.

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 was approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

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 11, Regulatory Matters below.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can

Table of Contents

reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has an obligation, it discloses such obligations with 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.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

See Note 13 of the Combined Notes to the Consolidated Financial Statements (Unaudited) for discussion of new accounting pronouncements.

Table of Contents

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, 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 FirstEnergy's nuclear generation facilities, respectively. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities.

FES' revenues are derived from sales to individual retail customers, sales to communities 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. In 2010, FES also supplied the POLR default service requirements of Met-Ed and Penelec.

The demand for electricity produced and sold by FES, along with the price of that electricity, is impacted by conditions in competitive power markets, global economic activity, economic activity in the Midwest and Mid-Atlantic regions and weather conditions.

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: Executive Summary- Operational Matters and Financial Matters, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $11 million in the first nine months of 2011 compared to the same period of 2010. The decrease was primarily due to higher operating expenses, an inventory reserve adjustment and the effect of mark-to-market adjustments, partially offset by lower non-core asset impairment charges.

Revenues

Total revenues decreased $152 million, or 3.5%, in the first nine months of 2011, compared to the same period of 2010, primarily due to reduced POLR and structured sales, partially offset by growth in direct and governmental aggregation sales.

The decrease in total revenues resulted from the following sources:

	Nine Months Ended September 30		Increase
Revenues by Type of Service	2011	2010	(Decrease)
	(In millions)		
Direct and Governmental Aggregation	$2,836	$1,814	$1,022
POLR and Structured Sales	798	2,014	(1,216)
Wholesale	288	265	23
Transmission	86	58	28
RECs	55	67	(12)
Other	88	85	3
Total Revenues	$4,151	$4,303	$(152)

	Nine Months Ended September 30		Increase
MWH Sales by Type of Service	2011	2010	(Decrease)
	(In thousands)		
Direct	33,893	20,675	63.9%
Governmental Aggregation	13,475	9,238	45.9%
POLR and Structured Sales	12,789	38,711	(67.0)%
Wholesale	2,714	3,281	(17.3)%

Total Sales	62,871	71,905	(12.6)%

137

Table of Contents

The increase in direct and governmental aggregation revenues of $1,022 million resulted from the acquisition of new commercial and industrial customers as well as new governmental aggregation contracts with communities in Ohio and Illinois that provided generation to approximately 1.7 million residential and small commercial customers at the end of September 2011 compared to approximately 1.2 million customers at the end of September 2010.
The decrease in POLR revenues of $1,216 million was due to lower sales volumes to Met-Ed, Penelec and the Ohio Companies, partially offset by increased sales to non-affiliates and higher unit prices to the Pennsylvania Companies. This decline is the result of FES no longer having the responsibility to supply these default service requirements and is consistent with our business strategy to selectively participate in POLR auctions.
Wholesale revenues increased by $23 million due to higher wholesale prices, partially offset by decreased volumes. The lower sales volumes were the result of decreased short-term (net hourly positions) transactions in MISO. Additional capacity revenues earned by generating units that moved to PJM were partially offset by losses on financially settled sales.

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 Sales:	
Effect of increase in sales volumes	$775
Change in prices	(41)
	734
Governmental Aggregation:	
Effect of increase in sales volumes	276
Change in prices	12
	288
Net Increase in Direct and Governmental Aggregation Revenues	$1,022

Source of Change in POLR Revenues	Increase (Decrease) (In millions)
POLR:	
Effect of decrease in sales volumes	$(1,349)
Change in prices	133
	$(1,216)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(46)
Change in prices	69
	$23

Transmission revenues increased by $28 million due primarily to higher MISO and PJM congestion revenue. The revenues derived from the sale of RECs decreased $12 million in the first nine months of 2011.
Operating Expenses
Total operating expenses decreased by $160 million in the first nine months of 2011, compared with the same period of 2010.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first nine months of 2011 compared with the same period last year:

Table of Contents

Source of Change in Fuel and Purchased Power	Increase (Decrease) (In millions)
Fossil Fuel:	
Change due to increased unit costs	$13
Change due to volume consumed	(54)
	(41)
Nuclear Fuel:	
Change due to increased unit costs	23
Change due to volume consumed	1
	24
Non-affiliated Purchased Power:	
Change due to increased unit costs	199
Change due to volume purchased	(451)
	(252)
Affiliated Purchased Power:	
Change due to decreased unit costs	(19)
Change due to volume purchased	(38)
	(57)
Net Decrease in Fuel and Purchased Power Costs	$(326)

Total fuel costs decreased by $17 million in the first nine months of 2011, compared to the same period of 2010, as a result of reduced generation at the fossil units, partially offset by higher fossil unit costs. Fossil unit costs increased primarily due to increased coal transportation costs. Nuclear fuel expenses increased primarily due to higher unit prices following the refueling outages that occurred in 2010.

Non-affiliated purchased power costs decreased by $252 million in the first nine months of 2011, compared to the same period of 2010, due to lower volumes purchased, partially offset by higher unit costs. The decrease in volume relates to the absence in 2011 of a 1,300 MW third-party contract associated with serving Met-Ed and Penelec that FES no longer has the requirement to serve. Affiliated purchased power costs decreased by $57 million in the first nine months of 2011, compared to the same period of 2010, due to lower unit costs and decreased volumes purchased.

Other operating expenses increased by $399 million in the first nine months of 2011, compared to the same period of 2010 due to the following:

- Transmission expenses increased by $216 million due primarily to increases in PJM of $332 million from higher congestion, network and line loss expense, partially offset by lower MISO transmission expenses of $116 million.
- Nuclear operating costs increased by $64 million due primarily to having two refueling outages, Perry and Beaver Valley 2, occurring in 2011. While Davis-Besse had a refueling outage in 2010, the work performed was largely capital-related.
- Fossil operating costs increased by $25 million due primarily to higher labor, contractor and material costs resulting from an increase in planned and unplanned outages.
- A $54 million provision for excess and obsolete material related to revised inventory practices adopted in connection with the Allegheny merger and an increase in mark-to-market adjustments of $24 million.

Impairment charges on long-lived assets decreased by $272 million due to a charge related to operational changes at certain smaller, coal-fired units that were recorded in the third quarter of 2010, partially offset by impairments of peaking facilities available for sale during the first nine months of 2011.

General taxes increased by $20 million due to an increase in revenue-related taxes.

Provision for depreciation increased by $19 million due to the AQC projects being placed in service at the end of 2010.

Table of Contents

Other Expense

Total other expense increased by $29 million in the first nine months of 2011, compared to the same period of 2010, primarily due to a $39 million decrease in capitalized interest associated with the completion of the Sammis AQC project in 2010, partially offset by a $6 million increase in investment income from higher NDT income.

Table of Contents

OHIO EDISON COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

OE is a wholly owned electric utility subsidiary of FirstEnergy. OE and its wholly owned subsidiary, Penn, conduct business in portions of Ohio and Pennsylvania, providing regulated electric distribution services. OE procures generation services for those franchise customers electing to retain OE and Penn as their power supplier.

For additional information with respect to OE, 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: Results of Operations- Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income was unchanged for the first nine months of 2011, compared to the same period of 2010, as decreased revenues and increased other operating expenses were offset by decreased purchased power costs.

Revenues

Revenues decreased by $187 million, or 13%, in the first nine months of 2011, compared with the same period in 2010, due to a decrease in generation revenues, partially offset by higher distribution and wholesale generation revenues.

Distribution revenues increased by $72 million in the first nine months of 2011, compared to the same period in 2010, due to increased KWH deliveries and higher average prices in all customer classes. The higher KWH deliveries in the residential class were driven primarily by increased load growth slightly offset by lower weather-related usage. The increase in distribution deliveries to commercial and industrial customers was primarily due to recovering economic conditions in OE's and Penn's service territory. Higher average prices in all customer classes were principally due to the recovery of deferred distribution costs.

Changes in distribution KWH deliveries and revenues in the first nine months of 2011, compared to the same period in 2010, are summarized in the following tables:

Distribution KWH Deliveries	Increase	
Residential	2.5	%
Commercial	0.9	%
Industrial	7.8	%
Increase in Distribution Deliveries	3.8	%

Distribution Revenues	Increase (In millions)
Residential	$37
Commercial	16
Industrial	19
Increase in Distribution Revenues	$72

Retail generation revenues decreased by $266 million primarily due to a decrease in KWH sales from increased customer shopping and lower average prices in all customer classes. Retail generation obligations 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. Lower KWH sales were primarily the result of increased customer shopping in the first nine months of 2011. The increases in customer shopping for residential, commercial and industrial customer classes were 21%, 12% and 7%, respectively.

Table of Contents

Decreases in retail generation KWH sales and revenues in the first nine months of 2011, compared to the same period in 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease	
Residential	(30.8	)%
Commercial	(36.3	)%
Industrial	(21.4	)%
Decrease in Retail Generation Sales	(29.9	)%

Retail Generation Revenues	Decrease (In millions)	
Residential	$(171	)
Commercial	(65	)
Industrial	(30	)
Decrease in Retail Generation Revenues	$(266	)

Wholesale generation revenues increased by $14 million in the first nine months of 2011, compared to the same period of 2010, 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 $192 million in the first nine months of 2011, compared to the same period of 2010. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)	
Purchased power costs	$(259	)
Other operating expenses	59	
Provision for depreciation	1	
Amortization of regulatory assets, net	1	
General taxes	6	
Net Decrease in Operating Expenses	$(192	)

Purchased power costs decreased in the first nine months of 2011, compared to the same period of 2010, due to lower KWH purchases resulting from reduced generation sales requirements coupled with lower unit costs. The increase in other operating expenses for the first nine months of 2011 compared to the same period of 2010 was principally due to expenses associated with refueling outages at OE's leased Perry Unit 1 and Beaver Valley Unit 2 that were absent in 2010. General taxes increased as a result of higher property taxes.

Table of Contents

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

CEI is a wholly owned electric utility subsidiary of FirstEnergy. CEI conducts business in northeastern Ohio, providing regulated electric distribution services. CEI also procures generation services for those customers electing to retain CEI as their power supplier.

For additional information with respect to CEI, 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: Results of Operations- Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent increased $1 million in the first nine months of 2011, compared to the same period of 2010. The increase in earnings was due to lower purchased power costs and amortization of regulatory assets, partially offset by lower revenues.

Revenues

Revenues decreased by $268 million, or 28%, in the first nine months of 2011, compared to the same period of 2010, due to lower retail generation and distribution revenues.

Distribution revenues decreased by $43 million in the first nine months of 2011, compared to the same period of 2010, due to lower average unit prices for the residential and industrial customer classes, partially offset by increased KWH deliveries to these customer classes. The lower average unit prices were the result of the absence of transition charges in 2011. Higher KWH deliveries to residential customers reflected increased load growth slightly offset by lower weather-related usage that also drove lower deliveries to commercial customers. In the industrial sector, KWH deliveries increased primarily as a result of recovering economic conditions in CEI's service territory.

Changes in distribution KWH deliveries and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	Increase (Decrease)	
Residential	1.6	%
Commercial	(0.6	)%
Industrial	1.6	%
Net Increase in Distribution Deliveries	0.8	%

Distribution Revenues	Increase (Decrease) (In millions)	
Residential	$(1	)
Commercial	7	
Industrial	(49	)
Net Decrease in Distribution Revenues	$(43	)

Retail generation revenues decreased by $224 million in the first nine months of 2011, compared to the same period of 2010, primarily due to lower KWH sales in all customer classes resulting from increased customer shopping and lower average unit prices for the commercial and residential customer classes. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. CEI defers the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings. Lower KWH sales were the result of increased customer shopping for residential, commercial and industrial classes of 18%, 10% and 37%, respectively. Lower average unit prices in the residential customer class were the result of generation credits in place for 2011.

Table of Contents

Decreases in retail generation sales and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(43.0)%
Commercial	(40.4)%
Industrial	(71.1)%
Decrease in Retail Generation Sales	(53.7)%

Retail Generation Revenues	Decrease (In millions)
Residential	$(87)
Commercial	(59)
Industrial	(78)
Decrease in Retail Generation Revenues	$(224)

Operating Expenses

Total operating expenses decreased by $262 million in the first nine months of 2011, compared to the same period of 2010. The following table presents the change from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)
Purchased power costs	$(227)
Other operating expenses	10
Amortization of regulatory assets, net	(56)
General taxes	11
Net Decrease in Operating Expenses	$(262)

Purchased power costs decreased due to lower KWH purchases resulting from reduced sales requirements. Other operating expenses increased due to 2011 inventory valuation adjustments. Amortization of regulatory assets decreased primarily due to the completion of transition cost recovery at the end of 2010 and deferred purchased power costs in 2011, partially offset by increased recovery of deferred distribution costs and the absence in 2011 of renewable energy credit expenses that were deferred in 2010. General taxes increased due to increased property taxes as compared to the same period of 2010.

Table of Contents

THE TOLEDO EDISON COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

TE is a wholly owned electric utility subsidiary of FirstEnergy. TE conducts business in northwestern Ohio, providing regulated electric distribution services. TE also procures generation services for those customers electing to retain TE as their power supplier.

For additional information with respect to TE, 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: Results of Operation- Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Earnings available to parent increased by $4 million in the first nine months of 2011, compared to the same period of 2010. The increase primarily resulted from lower purchased power costs from affiliates, partially offset by lower revenues and higher other operating expenses.

Revenues

Revenues decreased by $40 million, or 10%, in the first nine months of 2011, compared to the same period of 2010, due to a decrease in retail generation revenues, partially offset by higher distribution revenues and wholesale generation revenues.

Distribution revenues increased by $20 million in the first nine months of 2011, compared to the same period of 2010, due to higher residential, commercial and industrial revenues. Higher KWH deliveries to residential customers reflected increased load growth slightly offset by lower weather-related usage that also drove lower deliveries to commercial customers. In the industrial sector, KWH deliveries increased primarily as a result of recovering economic conditions in TE's service territory.

Changes in distribution KWH deliveries and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	Increase (Decrease)	
Residential	2.8	%
Commercial	(1.7	)%
Industrial	3.2	%
Net Increase in Distribution Deliveries	2.1	%

Distribution Revenues	Increase (In millions)
Residential	$11
Commercial	5
Industrial	4
Increase in Distribution Revenues	$20

Retail generation revenues decreased by $70 million in the first nine months of 2011, compared to the same period of 2010, due to lower KWH sales from increased customer shopping and lower unit prices for all customer classes. Lower KWH sales were the result of increased customer shopping, which has increased in the residential, commercial and industrial classes by 15%, 11% and 4%, respectively. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. TE defers the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings.

Table of Contents

Decreases in retail generation KWH sales and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease	
Residential	(28.9	)%
Commercial	(42.1	)%
Industrial	(10.5	)%
Decrease in Retail Generation Sales	(21.6	)%

Retail Generation Revenues	Decrease (In millions)	
Residential	$(25	)
Commercial	(17	)
Industrial	(28	)
Decrease in Retail Generation Revenues	$(70	)

Wholesale revenues increased by $11 million in the first nine months of 2011, compared to the same period of 2010, primarily due to higher revenues from sales to NGC from TE's leasehold interest in Beaver Valley Unit 2.

Operating Expenses

Total operating expenses decreased by $44 million in the first nine months of 2011, compared to the same period of 2010. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)	
Purchased power costs	$(73	)
Other operating expenses	25	
Deferral of regulatory assets, net	3	
General Taxes	1	
Net Decrease in Operating Expenses	$(44	)

Purchased power costs decreased in the first nine months of 2011, compared to the same period of 2010, due to lower KWH purchases resulting from reduced generation sales requirements in the first nine months of 2011 coupled with lower unit costs. The increase in other operating costs for the first nine months of 2011 was primarily due to expenses associated with the 2011 refueling outage at the leased Beaver Valley Unit 2 and an Ohio Supreme Court decision rendered in the second quarter of 2011 favoring a large industrial customer, both of which were absent in 2010. The net deferral of regulatory assets increased expenses due to more recovery of costs deferred in prior years during the first nine months of 2011, compared to the same period of 2010.

Other Expense

Other expense increased by $1 million in the first nine months of 2011, compared to the same period of 2010, due to lower nuclear decommissioning trust investment income.

Table of Contents

JERSEY CENTRAL POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

JCP&L is a wholly owned, electric utility subsidiary of FirstEnergy. JCP&L conducts business in New Jersey, providing regulated electric transmission and distribution services. JCP&L also procures generation services for franchise customers electing to retain JCP&L as their power supplier. 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 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: Results of Operations- Regulatory Assets, Capital Resources and Liquidity, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income decreased by $18 million in the first nine months of 2011, compared to the same period of 2010. The decrease was primarily due to lower revenues and higher other operating expenses, partially offset by reductions in purchased power costs and amortization of regulatory assets, net.

Revenues

Revenues decreased by $380 million, or 16%, in the first nine months of 2011, compared to the same period of 2010. The decrease in revenues was due to lower distribution, retail generation and wholesale generation revenues, partially offset by an increase in other revenues.

Distribution revenues decreased by $134 million in the first nine months of 2011, compared to the same period of 2010, primarily due to an NJBPU-approved rate adjustment that became effective March 1, 2011, for all customer classes, and lower KWH deliveries. The lower KWH deliveries to the residential class were influenced by decreased weather-related usage in the first nine months of 2011. Lower distribution deliveries to commercial and industrial customers reflected the impact of economic conditions to these sectors.

Decreases in distribution KWH deliveries and revenues in the first nine months of 2011 compared to the same period of 2010 are summarized in the following tables:

Distribution KWH Deliveries	Decrease	
Residential	(1.5	)%
Commercial	(2.4	)%
Industrial	(2.4	)%
Decrease in Distribution Deliveries	(2.0	)%

Distribution Revenues	Decrease (In millions)	
Residential	$(65	)
Commercial	(57	)
Industrial	(12	)
Decrease in Distribution Revenues	$(134	)

Retail generation revenues decreased by $234 million due to lower retail generation KWH sales in all customer classes primarily due to an increase in customer shopping. Customer shopping has increased for the residential, commercial and industrial classes by 11%, 10% and 5%, respectively. 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 to earnings.

147

Table of Contents

Decreases in retail generation KWH sales and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease	
Residential	(12.0	)%
Commercial	(23.7	)%
Industrial	(27.9	)%
Decrease in Retail Generation Sales	(15.7	)%

Retail Generation Revenues	Decrease (In millions)	
Residential	$(136	)
Commercial	(89	)
Industrial	(9	)
Decrease in Retail Generation Revenues	$(234	)

Wholesale generation revenues decreased by $21 million in the first nine months of 2011, compared to the same period of 2010, due to a decrease in PJM spot market energy sales.

Other revenues increased by $9 million in the first nine months of 2011, compared to the same period of 2010, primarily due to increases in PJM network transmission revenues and transition bond revenues.

Operating Expenses

Total operating expenses decreased by $347 million in the first nine months of 2011, compared to the same period of 2010. The following table presents changes from the prior period by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)	
Purchased power costs	$(254	)
Other operating expenses	38	
Provision for depreciation	1	
Amortization of regulatory assets, net	(134	)
General taxes	2	
Net Decrease in Operating Expenses	$(347	)

Purchased power costs decreased by $254 million in the first nine months of 2011 due to lower requirements from reduced retail generation sales. Other operating expenses increased by $38 million in the first nine months of 2011 principally from Hurricane Irene storm restoration maintenance costs, partially offset by lower labor costs. Amortization of regulatory assets, net, decreased by $134 million due to reduced cost recovery under the NJBPU-approved NUG tariffs that became effective March 1, 2011 and higher Hurricane Irene deferred storm restoration costs, partially offset by a write-off of nonrecoverable NUG costs.

Table of Contents

METROPOLITAN EDISON COMPANY

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Met-Ed is a wholly owned electric utility subsidiary of FirstEnergy. Met-Ed conducts business in eastern Pennsylvania, providing regulated electric transmission and distribution services. Met-Ed also procures generation service for those customers who have not elected an alternate power supplier. Met-Ed procures power under its DSP, in which full requirements products (energy, capacity, ancillary services, and applicable transmission services) are procured through descending clock auctions.

For additional information with respect to Met-Ed, 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: Results of Operations- Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $21 million in the first nine months of 2011, compared to the same period of 2010. The increase was primarily due to decreased purchased power, other operating expenses and amortization of net regulatory assets partially offset by decreased revenues.

Revenues

Revenues decreased by $446 million, or 32%, in the first nine months of 2011 compared to the same period of 2010, reflecting lower distribution, retail generation, wholesale generation and transmission revenues.

Distribution revenues decreased by $252 million in the first nine months of 2011, compared to the same period of 2010, primarily due to lower rates resulting from the DSP that began in 2011 that eliminated the transmission component from the distribution rate, partially offset by increased KWH deliveries. Higher KWH deliveries to residential customers reflected increased load growth slightly offset by lower weather-related usage that also drove lower deliveries to commercial customers. In the industrial sector, KWH deliveries increased primarily as a result of recovering economic conditions in Met-Ed's service territory.

Changes in distribution KWH deliveries and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	Increase (Decrease)	
Residential	0.5	%
Commercial	(1.1	)%
Industrial	3.1	%
Net Increase in Distribution Deliveries	1.1	%

Distribution Revenues	Decrease (In millions)	
Residential	$(95	)
Commercial	(71	)
Industrial	(86	)
Decrease in Distribution Revenues	$(252	)

Retail generation revenues decreased by $27 million in the first nine months of 2011 compared to the same period of 2010, due to lower KWH sales to all customer classes resulting from increased customer shopping. The impact of increased customer shopping is partially offset by higher generation rates that reflect the inclusion of transmission services under the DSP, effective January 1, 2011, for all customer classes. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. In 2011, Met-Ed began deferring the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings.

149

Table of Contents

Changes in retail generation KWH sales and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(1.1)%
Commercial	(46.4)%
Industrial	(90.2)%
Decrease in Retail Generation Sales	(43.9)%

Retail Generation Revenues	Increase (Decrease) (In millions)
Residential	$133
Commercial	(18)
Industrial	(142)
Net Decrease in Retail Generation Revenues	$(27)

Wholesale revenues decreased by $157 million in the first nine months of 2011, compared to the same period of 2010, reflecting lower RPM revenues for Met-Ed in the PJM market.

Transmission revenues decreased by $10 million in the first nine months of 2011 compared to the same period of 2010 primarily due to the termination of Met-Ed’s TSC rates effective January 1, 2011. Transmission costs are now a component of the cost of generation established under Met-Ed's generation procurement plan. Met-Ed deferred the difference between transmission revenues and transmission costs incurred, resulting in no material effect to earnings in the period.

Operating Expenses

Total operating expenses decreased $472 million in the first nine months of 2011 compared to the same period of 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)
Purchased power costs	$(241)
Other operating expenses	(189)
Provision for depreciation	1
Amortization of regulatory assets, net	(35)
General taxes	(8)
Net Decrease in Operating Expenses	$(472)

Purchased power costs decreased by $241 million in the first nine months of 2011 due to a decrease in KWH purchased to source generation sales requirements, partially offset by higher unit costs. Decreased power purchased from affiliates reflects the increase in customer shopping described above and the termination of Met-Ed's partial requirements PSA with FES at the end of 2010. Other operating costs decreased $189 million in the first nine months of 2011 compared to the same period in 2010 due to lower transmission congestion and transmission loss expenses that are now included in the cost of purchased power (see reference to deferral accounting above) partially offset by increased costs for energy efficiency programs. The amortization of regulatory assets decreased by $35 million in the first nine months of 2011 primarily due to the termination of transmission and transition tariff riders at the end of 2010. General taxes decreased by $8 million in the first nine months of 2011 primarily due to lower gross receipts taxes.

Other Expense

In the first nine months of 2011, interest income decreased by $3 million primarily due to reduced CTC stranded asset balances compared to the same period of 2010.

Table of Contents

PENNSYLVANIA ELECTRIC COMPANY

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Penelec is a wholly owned electric utility subsidiary of FirstEnergy. Penelec conducts business in northern and south central Pennsylvania, providing regulated electric transmission and distribution services. Penelec also procures generation service for those customers who have not elected an alternative power supplier. Penelec procures power under its DSP, in which full requirements products (energy, capacity, ancillary services and applicable transmission services) are procured through descending clock auctions.

For additional information with respect to Penelec, 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: Results of Operation- Regulatory Assets, Capital Resources and Liquidity, Guarantees and Other Assurances, Market Risk Information, Credit Risk, Outlook and New Accounting Standards and Interpretations.

Results of Operations

Net income increased by $2 million in the first nine months of 2011, compared to the same period of 2010. The increase was primarily due to lower purchased power and other operating costs, partially offset by lower revenues and higher net amortization of regulatory assets.

Revenues

Revenues decreased by $322 million, or 28%, in the first nine months of 2011 compared to the same period of 2010. The decrease in revenue was primarily due to lower distribution, retail generation, wholesale generation and transmission revenues.

Distribution revenues decreased by $13 million in the first nine months of 2011, compared to the same period of 2010, primarily due to lower rates resulting from the DSP that began in 2011 that eliminated the transmission component from the distribution rate, partially offset by a PPUC-approved rate adjustment for NUG costs. Lower KWH deliveries to commercial customers reflected decreased weather-related usage compared to the same period of 2010. Higher KWH deliveries to industrial customers were primarily due to recovering economic conditions in Penelec's service territories, compared to the first nine months of 2010.

Changes in distribution KWH deliveries and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Distribution KWH Deliveries	Increase (Decrease)	
Residential	—	%
Commercial	(3.0	)%
Industrial	4.3	%
Net Increase in Distribution Deliveries	1.0	%

Distribution Revenues	Increase (Decrease)	
	(In millions)	
Residential	$3	
Commercial	(22	)
Industrial	6	
Net Decrease in Distribution Revenues	$(13	)

Retail generation revenues decreased by $149 million in the first nine months of 2011, compared to the same period of 2010, due to lower KWH sales for all customer classes resulting from increased customer shopping. The impact of customer shopping is partially offset by higher generation rates that reflect the inclusion of transmission services under the DSP, effective January 1, 2011, for all customer classes. Retail generation obligations are attributable to non-shopping customers and are satisfied by generation procured through full-requirements auctions. In 2011, Penelec began deferring the difference between retail generation revenues and purchased power costs, resulting in no material effect to current period earnings.

Table of Contents

Changes in retail generation KWH sales and revenues in the first nine months of 2011, compared to the same period of 2010, are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(3.9)%
Commercial	(50.7)%
Industrial	(91.0)%
Decrease in Retail Generation Sales	(50.7)%

Retail Generation Revenues	Increase (Decrease) (In millions)
Residential	$72
Commercial	(58)
Industrial	(163)
Net Decrease in Retail Generation Revenues	$(149)

Wholesale generation revenues decreased by $151 million in the first nine months of 2011, compared to the same period of 2010, reflecting lower RPM revenues for Penelec in the PJM market.

Transmission revenues decreased by $9 million in the first nine months of 2011, compared to the same period of 2010, primarily due to the termination of Penelec’s TSC rates effective January 1, 2011. Transmission costs are now a component of the cost of generation established under Penelec's generation procurement plan. Penelec deferred the difference between transmission revenues and transmission costs incurred, resulting in no material effect to earnings for the period.

Operating Expenses

Total operating expenses decreased by $335 million in the first nine months of 2011, as compared with the same period of 2010. The following table presents changes from the prior year by expense category:

Operating Expenses - Changes	Increase (Decrease) (In millions)
Purchased power costs	$(326)
Other operating costs	(73)
Amortization of regulatory assets, net	67
General taxes	(3)
Net Decrease in Operating Expenses	$(335)

Purchased power costs decreased by $326 million in the first nine months of 2011, compared to the same period of 2010, due to decreased KWH purchased to source generation sales requirements. Decreased power purchased from affiliates reflected the increase in customer shopping described above and the termination of Penelec's partial requirements PSA with FES at the end of 2010. Other operating costs decreased by $73 million in the first nine months of 2011, due to lower transmission congestion and transmission loss expenses that are now included in the cost of purchased power (see reference to deferral accounting above). The net amortization of regulatory assets increased by $67 million in the first nine months of 2011, primarily due to reduced NUG deferrals as a result of a PPUC-approved increase in Penelec’s NUG cost recovery rider in January 2011.

Other Expenses

Other expenses increased by $3 million in the first nine months of 2011, compared to the same period of 2010, due to lower miscellaneous income from jobbing and contracting work.

Table of Contents

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

During the quarter ended September 30, 2011, other than changes resulting from the Allegheny merger discussed below, there have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FirstEnergy's, FES', OE's, CEI's, TE's, JCP&L's, Met-Ed's and Penelec's internal control over financial reporting.

On February 25, 2011, the merger between FirstEnergy and Allegheny closed. FirstEnergy is currently in the process of integrating Allegheny's operations, processes, and internal controls. See Note 2 to the consolidated financial statements in Part I, Item I for additional information relating to the merger.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Notes 10 and 11 of the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

For the quarter ended September 30, 2011, there have been no material changes to the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2010, as modified by changes to certain risk factors disclosed in our Quarterly Report on Form 10-Q for the period ended March 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 2011.

	Period			
	July	August	September	Third Quarter
Total Number of Shares Purchased[a]	69,273	114,813	502,921	687,007
Average Price Paid per Share	$44.57	$43.00	$43.63	$43.62
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	—	—	—	—

(a) 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 5. OTHER INFORMATION

Signal Peak Mine Safety

During the third quarter FirstEnergy, through its FEV wholly owned subsidiary, held a 50% interest in Global Mining Group LLC, a

153

Table of Contents

joint venture owning Signal Peak which is a company that constructed and operates the Bull Mountain Mine No. 1 (Mine), an underground coal mine near Roundup Montana. The operation of the Mine is subject to regulation by the Federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act).

On October 18, 2011, FirstEnergy announced that Gunvor Group, Ltd. signed an agreement to purchase a one-third interest in the Signal Peak coal mine in Montana. As a result of the sale, FirstEnergy, through its wholly owned subsidiary, FEV, will have a 33-1/3% interest in Global Mining Holding Company, LLC, a joint venture that owns Signal Peak.

Section 1503 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was enacted on July 21, 2010, contains new reporting requirements regarding mine safety, including, to the extent applicable, disclosing in periodic reports filed under the Securities Exchange Act of 1934 the receipt of certain notifications from the MSHA

Signal Peak received the following notices of violation and proposed assessments for the Mine under the Mine Act during the three months ended September 30, 2011:

	Signal Peak
Number of significant and substantial violations of mandatory health or safety standards under 104*	43
Number of orders issued under 104(b)*	—
Number of citations and orders for unwarrantable failure to comply with mandatory health or safety standards under 104(d)*	—
Number of flagrant violations under 110(b)(2)*	—
Number of imminent danger orders issued under 107(a)*	—
MSHA written notices under Mine Act section 104(e)* of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern	—
Pending Mine Safety Commission legal actions (including any contested citations issued)	5
Number of mining related fatalities	—
Total dollar value of proposed assessments	$6,104

*References to sections under Mine Act

The inclusion of this information in this report is not an admission by FirstEnergy that it controls Signal Peak or that Signal Peak is FirstEnergy's subsidiary for purposes of Section 1503 or for any other purpose,

More detailed information about the Mine, including safety-related data, can be found at MSHA's website, www.MSHA.gov. Signal Peak operates the Mine under the MSHA identification number 2401950.

ITEM 6. EXHIBITS

Exhibit Number		
FirstEnergy		
12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

FES		
12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.
OE		
12		Fixed charge ratios

Table of Contents

31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of Ohio Edison Company. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

CEI

12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of The Cleveland Electric Illuminating Company. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

TE

12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of The Toledo Edison Company. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

JCP&L

12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of Jersey Central Power & Light Company. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

Met-Ed

12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of Metropolitan Edison Company. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

Penelec

12		Fixed charge ratios
31.1		Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
31.2		Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
32		Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	*	The following materials from the Quarterly Report on Form 10-Q of Pennsylvania Electric Company. for the period ended September 30, 2011, 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 tagged as blocks of text and (v) document and entity information.

* Users of these data are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is 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, is deemed not filed for purposes of section 18 of

155

Table of Contents

the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.
Pursuant to reporting requirements of respective financings, FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec are required to file fixed charge ratios as an exhibit to this Form 10-Q.
Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed nor Penelec 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.

Table of Contents

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 1, 2011

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

OHIO EDISON COMPANY
Registrant

THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY
Registrant

THE TOLEDO EDISON COMPANY
Registrant

METROPOLITAN EDISON COMPANY
Registrant

PENNSYLVANIA ELECTRIC COMPANY
Registrant

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

JERSEY CENTRAL POWER & LIGHT COMPANY
Registrant

/s/ K. Jon Taylor
K. Jon Taylor
Controller
(Principal Accounting Officer)